CANADIAN UTILITIES IS A DIVERSIFIED, CANADIAN BASED, INTERNATIONAL GROUP OF COMPANIES

CANADIAN UTILITIES

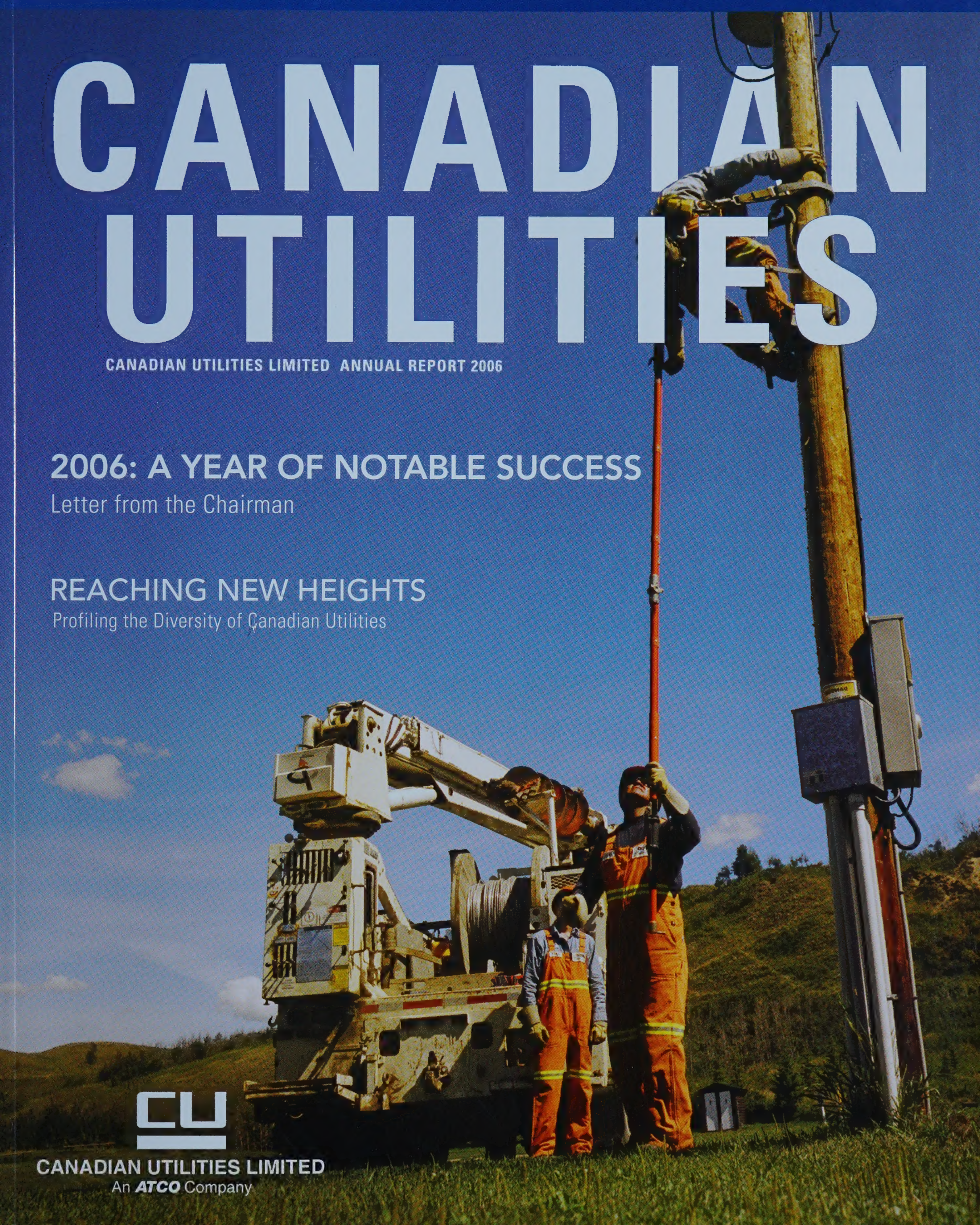
CANADIAN UTILITIES LIMITED ANNUAL REPORT 2006

2006: A YEAR OF NOTABLE SUCCESS

Letter from the Chairman

REACHING NEW HEIGHTS

Profiling the Diversity of Canadian Utilities



CANADIAN UTILITIES LIMITED
An ATCO Company

CANADIAN UTILITIES LIMITED

ANNUAL REPORT 2006

Canadian Utilities Limited is a diversified, Canadian based, international group of companies focused on profitable sustainable growth and achievement with $7.0 billion in assets and more than 6,000 people actively engaged in Power Generation, Utilities (natural gas and electricity transmission and distribution) and Global Enterprises, with companies active in technology, logistics and energy services.

COVER:

ATCO Electric delivers electric energy to towns and cities, farms and businesses in 245 Alberta communities.

FINANCIAL Highlights:

CONSOLIDATED ANNUAL RESULTS

	YEAR ENDED DECEMBER 31	
(millions of Canadian dollars except per share data)	**2006**	2005
FINANCIAL		
Revenues	**2,430.4**	2,515.8
Earnings attributable to Class A & Class B shares	**323.9**	265.6
Total assets	**6,993.5**	6,817.8
Class A & Class B share owners' equity	**2,324.7**	2,223.5
Funds generated by operations	**657.5**	659.3
Purchase of property, plant and equipment	**567.7**	526.7
CLASS A NON-VOTING & CLASS B COMMON SHARE DATA		
Earnings per share	**2.57**	2.09
Diluted earnings per share	**2.56**	2.08
Dividends paid per share	**1.40**	1.10
Equity per share	**18.54**	17.52
Shares outstanding (thousands)	**125,388**	126,892
Weighted average shares outstanding (thousands)	**126,219**	126,902

FORWARD LOOKING INFORMATION:

This Annual Report contains forward-looking statements pertaining to contractual obligations, planned capital expenditures, the impact of changes in government regulation and non-regulated generating capacity subject to long term contracts. The Corporation's actual results could differ materially from those anticipated in these forward-looking statements as a result of regulatory decisions, competitive factors in the industries in which the Corporation operates, prevailing economic conditions, and other factors, many of which are beyond the control of the Corporation.

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4 A REMARKABLE YEAR

President's Letter

6 REACHING NEW HEIGHTS

Read an overview of our companies.

Five Year Total Return on $100 Investment

Canadian Utilities Limited Share Ownership

It is important for prospective owners to understand that Canadian Utilities Limited is a diversified group of companies principally controlled by ATCO Ltd., which in turn is principally controlled by Sentgraf, a Southern Family holding company.

It is also important for present and prospective share owners to understand that Canadian Utilities share registry has both non-voting and voting common shares.

	COMPOUND GROWTH RATE	CUMULATIVE RETURN
Class A Non-Voting	18.0%	$229
Class B Common	18.3%	$232
S&P/TSX Composite	13.1%	$185

The graph compares the cumulative share owner return over the last five years on the Class A non-voting and Class B common shares of the Corporation (assuming reinvestment of dividends) with the cumulative total return of the S&P/TSX composite index.

Chairman's Letter to Share Owners

BY R.D. SOUTHERN

In the 27 years since the repatriation of Canadian Utilities from the United States by ATCO Group, Canadian Utilities has consistently represented solid performance with a record of quality service and products, customer satisfaction, an excellent safety record, and good returns for our investors.

There have, of course, been many changes from our modest beginnings, but to comprehend the significance and impact of our group of companies today, I am compelled to the view that the renewal of family leadership through three generations, with their founding beliefs, philosophies and fundamental attitudes toward commerce, have served us well.

It probably is not for me to say, but, under the ATCO banner, Canadian Utilities has become an enterprise of much national pride and considerable international acclaim… while, at home, our company is still truly admired and respected by the people of Alberta, with representation and opportunities in almost every hamlet, town and city throughout our home province, the Yukon, Nunavut and the Northwest Territories. Indeed, when added to our other markets in Canada and the world, the future holds much promise for our endeavours in the years ahead.

Our President's letter, together with a detailed reading of this Report, will give you a better understanding of our people's devotion and commitment to our founding principle of "Excellence" and, because of our trans-generational culture, each of our Executives brings a sense of responsible ownership to steer our companies across business cycles.

They have worked hard to create our present financial strength which allows us to respond to the many opportunities unfolding for our companies in our core market area.

On behalf of our Share Owners and the many constituencies we serve, I would like to thank, in the most genuine way possible, our Directors, whose commitment has given us this trans-generational success. They have applied their knowledge and experience with distinction to their oversight responsibilities and our value creation strategies. Individually and collectively they are a great asset of which all our people and all our investors can be proud.

… And… on behalf of our Board of Directors, may I sincerely compliment the some 6,000 people who make up our company for their talents, competencies, spirit and dedication, in making 2006 such an outstanding year of success and progress… well done… well done!

Respectfully submitted,

R.D. Southern

CHAIRMAN OF THE BOARD

GENERAL INFORMATION:

INCORPORATION
Canadian Utilities Limited was incorporated under the laws of Canada on May 18, 1927 and was continued under the Canada Business Corporations Act by Articles of Continuance on August 15, 1979.

ANNUAL MEETING
The Annual Meeting of Share Owners will be held at 10:00 a.m., M.D.T. Thursday, May 3, 2007 at The Fairmont Hotel Macdonald, 10065-100 Street, Edmonton, Alberta.

AUDITORS
PricewaterhouseCoopers LLP
Calgary, Alberta

COUNSEL
Bennett Jones LLP
Calgary, Alberta

TRANSFER AGENT AND REGISTRAR
Class A Non-Voting and
Class B Common Shares and
Second Preferred
(Series Q, R, S, W and X) Shares
CIBC Mellon Trust Company
Calgary/Montreal/Toronto/Vancouver

TRUSTEE AND REGISTRAR
Debentures
CIBC Mellon Trust Company

STOCK EXCHANGE LISTINGS
Class A Non-Voting Symbol CU
Class B Common Symbol CU.X
Listing: The Toronto Stock Exchange

CUMULATIVE REDEEMABLE
SECOND PREFERRED SHARES
5.90% Series Q CU.PR.T
5.30% Series R CU.PR.V
6.60% Series S CU.PR.D
5.80% Series W CU.PR.A
6.00% Series X CU.PR.B
Listing: The Toronto Stock Exchange

ATCO GROUP ANNUAL REPORTS
Annual Reports to Share Owners and Management's Discussion and Analysis for Canadian Utilities Limited and its parent company, ATCO Ltd., are available upon request from:
ATCO Ltd. & Canadian Utilities Limited
1400, 909 – 11th Avenue SW
Calgary, Alberta T2R 1N6
Telephone: (403) 292-7500
Website: www.canadian-utilities.com

SHARE OWNER INQUIRIES
Dividend information and other inquiries concerning shares should be directed to:
CIBC Mellon Trust Company
Stock Transfer Department
600 The Dome Tower
333 – 7th Avenue SW
Calgary, Alberta T2P 2Z1
Telephone: 1-800-387-0825
Website: www.cibcmellon.com

Printed in Canada

President's Letter

BY NANCY C. SOUTHERN

Dear Share Owners,

We had a remarkable year in Canadian Utilities Limited improving our 2006 earnings per share by 23 per cent over 2005 and, at the same time, experiencing favourable growth throughout all facets of our enterprise. Much of this was due to the world's commodity driven economy which indeed provided our company with an economic environment that exceeded our expectations.

You will notice in our financial statements that our utility companies' earnings do not appear as robust as our other segments. This is a direct result of low interest rates which are the basis for the Alberta Energy and Utilities Board's determination of its utility rate of return.

In simplified terms, the Alberta Energy and Utilities Board uses a formula that is based on the November forecast of the yield on long term Goverment of Canada bonds. Each year, this formula automatically adjusts for changes in the forecast. When this formula was first introduced in 2004, the forecast yield on the long term bonds was 5.68 per cent; since then it has decreased steadily to 4.78 per cent in 2006 and 4.22 per cent in 2007. This reduction has translated into a corresponding decline in the utility rate of return: from 9.60 per cent in 2004 to 8.93 per cent in 2006 and 2007 will see a further reduction in the rate of return – to 8.51 per cent.

This formula is applied on an industry wide basis. Therefore, with the support of other utility companies, we have initiated discussions with the Alberta Energy and Utilities Board to explore the possibility of a less punitive formula.

The positive offset to the rate of return for our utilities is our unprecedented growth required to meet Alberta's infrastructure demands.

Our 2006 capital investment in ATCO Gas, ATCO Pipelines, and ATCO Electric was $500 million and our outlook over the next year is for a further $650 million of investment that will be required of all our regulated companies.

These capital expenditures will be primarily for new electrical transmission to support the growth in oilsands and heavy oil projects, as well as natural gas distribution hookups to new homes which will accommodate the population expansion in Alberta.

Provincial growth has also impacted our company's power generation business as excess supply of power has decreased thereby increasing the price per megawatt available to generators.

Coincidentally, in the United Kingdom, this same tightening of power supply is also occurring, producing higher margins for our 25 percent share of the 1,000 MW gas fired, combined cycle Barking power plant.

We think these conditions will continue throughout our international power generation markets, and we expect the development of new power projects to be on the horizon. This will allow us to capitalize on our well developed plans for clean generation opportunities. The caveat, however, will be the final outcome of environmental legislation and regulation in Canada, the United Kingdom, and Australia.

Led by ATCO Midstream, our Global Enterprises business group realized record performance in 2006. Frac spreads, gas throughput on our system and storage differentials all contributed to ATCO Midstream's performance.

While 2006 delivered strong earnings, our Directors and Officers remain aware that many of our principal operating subsidiaries are cyclical in nature and results may fluctuate considerably in the future.

The heated Alberta and world markets continue to put stress on human resources and materials availability. Potential staffing shortfalls are being addressed with the implementation of a comprehensive global recruitment strategy designed to complement our current workforce.

We have increased focus on our project controls and operational efficiencies to proactively manage equipment, supplies, and labour costs. We are also continuing to improve on our operating procedures and processes to validate the accuracy of our real time information flow and due diligence competencies.

Our overarching preferred strategy for Canadian Utilities Limited is to continue improving the strong balance sheet we have created. Our growing capacity will allow us to invest more in our existing activities and give us the flexibility to act on other opportunities such as a bolt on accretive acquisition during an economic downturn.

The diversity of our enterprise has proven to be a successful model. It has the merit of stable utility earnings while, at the same time, stimulating our workforce to remain close to our customers and continue to develop profitable new products and services in our non-regulated divisions.

Business is still about people. It is what we believe gives us our competitive advantage. We have a great company that is made so by 6,000 men and women who each and every day bring determined commitment and strong basic values of loyalty and integrity to their work.

I also want to recognize and extend my heartfelt appreciation to our Board of Directors for their wise counsel on our strategies and their dedication to excellence in our corporate governance. They remain ever mindful of their duties to protect and bring fair-minded judgment for both majority and minority share owners.

Finally, I hope you will join me in congratulating our Chairman on ATCO Group's 60th birthday. He, along with his father, S.D. Southern, and the talented and dedicated men and women who have followed them, have created an enterprise of excellence based on basic family values, which continues to deliver outstanding compounding value for the owners of our shares.

Thank you!

Sincerely,

N.C. South

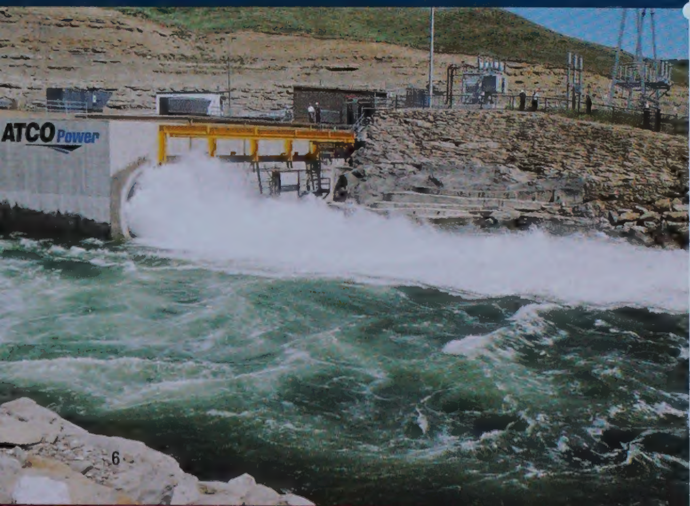
N.C. Southern

PRESIDENT & CHIEF EXECUTIVE OFFICER

ATCO GAS is an Alberta wide natural gas distribution company serving nearly one million customers in almost 300 communities. With more than 90 years experience providing natural gas service to homes, farms and businesses, ATCO Gas is headquartered in Edmonton with 62 district offices where its employees live and work. In part due to Alberta's booming economy, capital expenditures in 2006 doubled from five years ago to $167.4 million as the company expanded a delivery system consisting of 35,935 kilometres of pipeline.

ATCO PIPELINES operates a natural gas pipeline system of 8,419 kilometres connecting producers with Alberta markets and providing interconnections with all major pipeline systems that export gas out of the province. ATCO Pipelines is a significant player in the gas transportation industry with on-system receipts exceeding 1.3 billion cubic feet (bcf) per day and peak delivery of 3.7 bcf per day. Customers can access the markets of their choice through ATCO Pipelines' innovative, flexible and cost-effective transportation solutions.

ATCO ELECTRIC serves more than 186,000 customers in northern and east-central Alberta and through its subsidiaries, Yukon Electrical and Northland Utilities, also serves consumers in Canada's far north. Headquartered in Edmonton with 37 service offices, ATCO Electric in 2006 employed 1,088 people, including engineers, accountants, line crews, servicemen, technologists and clerical staff. For 80 years, ATCO Electric has delivered power to homes, farms and businesses, in cities, towns, Native reserves and Metis settlements – in 245 communities in all.

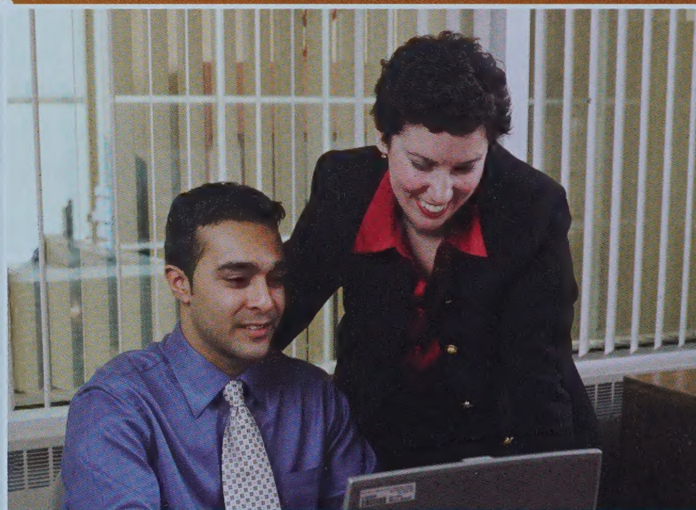


ATCO POWER is a world-class developer, construction manager, owner and operator of technologically advanced and environmentally progressive independent power generation plants. Established in 1988, projects have been developed in the United Kingdom, Australia, British Columbia, Alberta, Saskatchewan and, most recently, in Ontario. ATCO Power now has assets of $2.24 billion representing 51 per cent ownership in approximately 4,800 MW of capacity at 19 facilities operated by the company. Following deregulation in Alberta, the regulated generating plants of ATCO Electric were transferred to an ATCO Power company.

ATCO MIDSTREAM provides gas gathering, processing, storage, and natural gas liquids solutions to its customers within the Canadian natural gas industry. With almost 1,000 kilometres of field gathering lines, the company has a diverse asset base including 11 natural gas gathering and processing facilities and four natural gas extraction facilities, which together have a total processing capacity of more than 1.5 billion cubic feet of gas per day. The company also provides innovative natural gas storage services with more than 40 billion cubic feet of capacity available.

ATCO FRONTEC has proven expertise in the delivery of technical services, site support, facilities management and camp services to a wide range of customers and varied industries throughout Canada, into Alaska, across Europe and in the Middle East. Unique opportunities created from various joint venture and aboriginal alliances, as well as increasing support for deployed military operations, serve as foundations of the company business. Headquartered in Calgary, the company won its first contract with the United Nations in 2006 to provide catering and camp support services at four locations in Kosovo.

ATCO I-TEK delivers customer care, billing and information technology solutions to a diverse group of clients that operate around the world. Headquartered in Edmonton, ATCO I-Tek is a disciplined business-to-business service provider with proven processes, controls and a service-oriented team of more than 900 people. In 2006, ATCO I-Tek answered more than 1.7 million customer calls, produced 12 million statements, processed more than 10.5 million payments and collected close to $3.0 billion in revenue for its clients.



ATCO TRAVEL is one of the largest corporate travel management companies in Canada, with its head office in Calgary, and branch offices in Edmonton, Fort McMurray and Ottawa. With almost 130 employees and independent associates, ATCO Travel in 2006 was recognized as the winner of the Association of Canadian Travel Agents Atlas Award as 'Travel Agent of the Year' for Alberta and N.W.T. ATCO Travel has established a leading reputation by providing clients with superior quality and personalized service in both corporate travel management and vacation services.

Canadian Utilities Limited

Financial Statements

MD&A

Management's Discussion & Analysis

KAREN M. WATSON

Senior Vice President & Chief Financial Officer

Financial Achievements 2006

- Earnings per share increased to $2.57 from $2.09 in 2005.
- Earnings increased by $58.3 million to $323.9 million from $265.6 million in 2005.
- Dividends paid per Class A and Class B share increased by $0.30 to $1.40 from $1.10 in 2005. This increase included a Special Dividend of $0.25 paid to Class A and Class B share owners on September 1, 2006. Dividends have increased each year since 1972 – 34 years!
- Return on common equity was 14.3 per cent compared to 12.2 per cent in 2005.
- Total assets increased by $176 million to $7.0 billion compared to $6.8 billion in 2005.
- Long term debt increased by $181 million to $2.4 billion.
- Non-recourse long term debt decreased by $47 million to $627 million.
- Share owners' equity increased by $101 million to $2.3 billion compared to $2.2 billion in 2005.
- Funds generated by operations is virtually unchanged at $658 million.
- Capital expenditures were $568 million in 2006 compared to $527 million in 2005. Over the previous five years, capital expenditures averaged $539 million per year.
- CU issued $320 million of debentures and $36 million of other debt in 2006. CU redeemed $175 million of debentures in 2006.
- CU redeemed $65 million of non-recourse long term debt in 2006.
- CU purchased $73 million of Class A non-voting shares in 2006.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL REPORTING

Management is responsible for the preparation of the consolidated financial statements, management's discussion and analysis of financial condition and results of operations and other financial information relating to the Corporation contained in this annual report. The consolidated financial statements have been prepared in conformity with Canadian generally accepted accounting principles using methods appropriate for the industries in which the Corporation operates and necessarily include some amounts that are based on informed judgments and best estimates of management. The financial information contained elsewhere in the annual report is consistent with that in the consolidated financial statements.

Management has established internal accounting control systems to meet its responsibility for reliable and accurate reporting. These control systems are subject to periodic review by the Corporation's internal auditors.

PricewaterhouseCoopers, our independent auditors, are engaged to express a professional opinion on the consolidated financial statements.

The Board of Directors, through its Audit Committee comprised entirely of outside Directors, oversees management's responsibilities for financial reporting. The Audit Committee meets regularly with management, the internal auditors and the independent auditors to discuss auditing and reporting on financial matters, to assure that management is carrying out its responsibilities and to review and approve the consolidated financial statements. The auditors have full and free access to the Audit Committee and management.

KM Watson

K.M. Watson
Senior Vice President & Chief Financial Officer

PG Wright

P.G. Wright
Vice President, Finance and Controller

February 21, 2007

AUDITORS' REPORT

TO THE SHARE OWNERS OF CANADIAN UTILITIES LIMITED

We have audited the consolidated balance sheets of Canadian Utilities Limited as at December 31, 2006 and 2005 and the consolidated statements of earnings and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement preparation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2006 and 2005 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta

February 21, 2007

CANADIAN UTILITIES LIMITED

CONSOLIDATED STATEMENT OF EARNINGS AND RETAINED EARNINGS

(Millions of Canadian Dollars except per share data)

		Three Months Ended December 31		Year Ended December 31	
	Note	**2006**	2005	**2006**	2005
		(Unaudited)			
Revenues		**$ 671.1**	$ 680.3	**$ 2,430.4**	$ 2,515.8
Costs and expenses					
Natural gas supply		**10.2**	18.3	**36.4**	162.2
Purchased power		**12.5**	12.2	**46.1**	45.4
Operation and maintenance		**243.5**	261.7	**950.3**	1,003.6
Selling and administrative		**74.9**	57.3	**207.5**	190.4
Depreciation and amortization		**95.6**	84.5	**348.5**	311.5
Interest	7, 12	**54.6**	51.4	**222.9**	210.0
Franchise fees		**42.4**	49.5	**150.4**	152.3
		533.7	534.9	**1,962.1**	2,075.4
		137.4	145.4	**468.3**	440.4
Interest and other income	6	**18.9**	10.6	**58.5**	36.6
Earnings before income taxes		**156.3**	156.0	**526.8**	477.0
Income taxes	7	**47.4**	58.0	**167.1**	175.6
		108.9	98.0	**359.7**	301.4
Dividends on equity preferred shares		**8.9**	8.9	**35.8**	35.8
Earnings attributable to Class A and Class B shares		**100.0**	89.1	**323.9**	265.6
Retained earnings at beginning of period		**1,741.1**	1,670.4	**1,721.9**	1,603.4
		1,841.1	1,759.5	**2,045.8**	1,869.0
Dividends on Class A and Class B shares		**36.3**	34.9	**176.7**	139.6
Purchase of Class A shares and other direct charges to retained earnings	8	**0.4**	2.7	**64.7**	7.5
Retained earnings at end of period		**$ 1,804.4**	$ 1,721.9	**$ 1,804.4**	$ 1,721.9
Earnings per Class A and Class B share	15	**$ 0.80**	$ 0.70	**$ 2.57**	$ 2.09
Diluted earnings per Class A and Class B share	15	**$ 0.80**	$ 0.69	**$ 2.56**	$ 2.08
Dividends paid per Class A and Class B share	15	**$ 0.29**	$ 0.275	**$ 1.40**	$ 1.10

CANADIAN UTILITIES LIMITED
CONSOLIDATED BALANCE SHEET
(Millions of Canadian Dollars)

	Note	December 31	
		2006	2005
ASSETS			
Current assets			
Cash and short term investments	18	**$ 798.8**	$ 824.6
Accounts receivable		**362.3**	353.4
Inventories		**96.5**	88.0
Regulatory assets	2	**13.3**	19.1
Prepaid expenses		**23.6**	19.9
		1,294.5	1,305.0
Property, plant and equipment	9	**5,426.1**	5,208.7
Regulatory assets	2	**43.2**	35.0
Other assets	10	**229.7**	269.1
		$ 6,993.5	$ 6,817.8
LIABILITIES AND SHARE OWNERS' EQUITY			
Current liabilities			
Bank indebtedness		**$ -**	$ 0.2
Accounts payable and accrued liabilities		**338.8**	342.6
Income taxes payable		**22.7**	26.7
Future income taxes	7	**0.3**	4.1
Regulatory liabilities	2	**0.5**	6.4
Non-recourse long term debt due within one year	12	**59.3**	57.0
		421.6	437.0
Future income taxes	7	**194.7**	200.3
Regulatory liabilities	2	**148.8**	161.9
Deferred credits	13	**229.0**	253.8
Long term debt	12	**2,411.5**	2,231.0
Non-recourse long term debt	12	**626.7**	673.8
Equity preferred shares	14	**636.5**	636.5
Class A and Class B share owners' equity			
Class A and Class B shares	15	**516.0**	519.1
Contributed surplus	16	**1.2**	0.7
Retained earnings		**1,804.4**	1,721.9
Foreign currency translation adjustment		**3.1**	(18.2)
		2,324.7	2,223.5
		$ 6,993.5	$ 6,817.8

N.C. Southern

N.C. SOUTHERN
DIRECTOR

B.K. French

B.K. FRENCH
DIRECTOR

CANADIAN UTILITIES LIMITED
CONSOLIDATED STATEMENT OF CASH FLOWS

(Millions of Canadian Dollars)

		Three Months Ended December 31		Year Ended December 31	
		(Unaudited)			
	Note	**2006**	2005	**2006**	2005
Operating activities					
Earnings attributable to Class A and Class B shares		**$100.0**	$ 89.1	**$323.9**	$265.6
Adjustments for:					
Depreciation and amortization		**95.6**	84.5	**348.5**	311.5
Future income taxes		**11.3**	0.6	**(1.6)**	7.7
Deferred availability incentives		**(41.0)**	14.5	**(20.2)**	13.7
TXU Europe settlement – net of income taxes	5	**(3.3)**	(3.7)	**(1.6)**	45.8
Other		**5.8**	2.8	**8.5**	15.0
Funds generated by operations		**168.4**	187.8	**657.5**	659.3
Changes in non-cash working capital	17	**(48.5)**	(1.2)	**(39.6)**	90.2
Cash flow from operations		**119.9**	186.6	**617.9**	749.5
Investing activities					
Purchase of property, plant and equipment		**(184.0)**	(181.2)	**(567.7)**	(526.7)
Proceeds on transfer of retail energy supply businesses - net of income taxes	3	**-**	-	**-**	43.4
Costs on disposal of property, plant and equipment		**(4.3)**	(4.4)	**(10.4)**	(5.9)
Contributions by utility customers for extensions to plant		**20.1**	6.7	**81.3**	44.1
Non-current deferred electricity costs		**(8.7)**	(5.7)	**4.5**	(15.7)
Changes in non-cash working capital	17	**15.4**	24.4	**(18.3)**	(3.4)
Income tax reassessment	7	**-**	-	**(12.8)**	-
Other		**0.9**	(0.1)	**(4.1)**	(6.2)
		(160.6)	(160.3)	**(527.5)**	(470.4)
Financing activities					
Issue of long term debt		**320.0**	185.0	**355.5**	222.0
Repayment of long term debt		**(175.0)**	(35.4)	**(175.0)**	(167.1)
Repayment of non-recourse long term debt		**(12.6)**	(9.1)	**(64.6)**	(54.3)
Net issue (purchase) of Class A shares		**1.9**	(2.7)	**(67.5)**	(2.7)
Dividends paid to Class A and Class B share owners		**(36.3)**	(34.9)	**(176.7)**	(139.6)
Changes in non-cash working capital	17	**(0.1)**	0.3	**(0.1)**	3.1
Other		**(2.6)**	(2.1)	**(3.9)**	(3.2)
		95.3	101.1	**(132.3)**	(141.8)
Foreign currency translation		**11.6**	0.2	**16.3**	(11.2)
Cash position (1)					
Increase (decrease)		**66.2**	127.6	**(25.6)**	126.1
Beginning of period		**732.6**	696.8	**824.4**	698.3
End of period		**$798.8**	$824.4	**$798.8**	$824.4

(1) *Cash position consists of cash and short term investments less current bank indebtedness.*

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(tabular amounts in millions of Canadian dollars)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Financial Statement Presentation

The accompanying consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and include the accounts of Canadian Utilities Limited and its subsidiaries, including a proportionate share of joint venture investments (the "Corporation"). Principal operations are Utilities (ATCO Electric, ATCO Gas, ATCO Pipelines), Power Generation (ATCO Power, Alberta Power (2000)) and Global Enterprises (ATCO Midstream, ATCO Frontec, ATCO I-Tek). Significant joint venture investments consist principally of power generation plants; a substantial portion of Power Generation's operations are conducted through joint ventures.

Certain comparative figures have been reclassified to conform to the current presentation.

Rate Regulation

ATCO Electric and its subsidiaries, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical, the ATCO Gas and ATCO Pipelines divisions of ATCO Gas and Pipelines Ltd. and the generating plants of Alberta Power (2000), all of which are wholly owned subsidiaries of Canadian Utilities Limited's wholly owned subsidiary, CU Inc., are collectively referred to in these consolidated financial statements as the "regulated operations". Accounting for rate regulated operations is described in Note 2.

Use of Estimates

The preparation of the Corporation's consolidated financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the year. On an on-going basis, management reviews its estimates, particularly those related to depreciation and amortization methods, useful lives and impairment of long-lived assets, amortization of deferred availability incentives, asset retirement obligations and employee future benefits, using currently available information. Changes in facts and circumstances may result in revised estimates, and actual results could differ from those estimates.

Revenue Recognition

For regulated operations, revenues are recognized in a manner that is consistent with the underlying rate design as mandated by the regulator.

Revenues from ATCO Gas' regulated distribution of natural gas include variable charges, which are recognized on the basis of meter readings upon delivery of natural gas to customers and include an estimate of usage not yet billed, and fixed charges, based on the provision of the distribution service during the period. Revenues from the sale of natural gas by ATCO Gas from storage, which ended on March 31, 2005, were recognized upon delivery.

Revenues from ATCO Electric's regulated distribution of electricity include variable charges, which are recognized on the basis of meter readings upon delivery of electricity to customers and include an estimate of usage not yet billed, and fixed charges, based on the provision of the distribution service during the period. Revenues for the use of ATCO Electric's regulated transmission facilities are based on an annual tariff and are recognized evenly throughout the year.

Revenues from ATCO Pipelines' regulated transportation of natural gas are recognized on the basis of contractual arrangements. For certain services, revenues are recognized on the basis of meter readings upon delivery of natural gas to customers and include an estimate of usage not yet billed.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Revenues from regulated sales and distribution of natural gas and electricity by other regulated operations, excluding Alberta Power (2000), are recognized upon delivery, primarily on the basis of meter readings, and include an estimate of usage not yet billed.

Revenues from generating plants are recognized upon delivery of output or upon availability of delivery as prescribed by contractual arrangements. Incentives and penalties associated with Power Purchase Arrangements ("PPA") are recognized as described under the accounting policy for deferred availability incentives.

Revenues from ATCO Midstream's natural gas storage and processing capacity are recognized on the basis of contractual arrangements, and revenues from the sale of natural gas liquids are recognized upon delivery.

Revenues from the supply of contracted services are recorded by the percentage of completion method; full provision is made for any anticipated loss. Other revenues are recognized when products are delivered or services are provided.

Natural Gas Supply

Natural gas supply expense for regulated operations, which consists of natural gas volumes purchased for sales to customers (see Note 3 regarding natural gas supply of regulated operations following the transfer of retail energy supply businesses by ATCO Gas and ATCO Electric in 2004), is based on actual costs incurred.

Natural gas supply expense for other subsidiaries, which consists of natural gas volumes purchased for natural gas liquids extraction and sales to third parties, is based on actual costs incurred.

Purchased Power

Purchased power expense in the Yukon Territory and the Northwest Territories is based on the actual cost of electricity purchased. The amount included in customer rates in the Yukon Territory is based on actual costs and in the Northwest Territories is based on forecast cost. Revenues are adjusted for variances from forecast cost, and the variances are deferred until such time as approval from the regulator is obtained for refund to or collection from customers.

Income Taxes

The regulated operations follow the method of accounting for income taxes that is consistent with the method of determining the income tax component of their rates. When future income taxes are not provided in the income tax component of current rates, such future income taxes are not recognized to the extent that it is expected that they will be recovered from customers through inclusion in future rates.

Other subsidiaries follow the liability method of accounting for income taxes. Under this method, future tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. Future tax liabilities and assets are measured using enacted and substantively enacted tax rates. The effect on future tax liabilities and assets of a change in tax rates is recognized in income in the period that the change occurs.

Inventories

Inventories are valued at the lower of average cost or net realizable value.

Property, Plant and Equipment

Property, plant and equipment are recorded at cost less accumulated depreciation and unamortized contributions by utility customers for extensions to plant.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Regulated operations include in property, plant and equipment an allowance for funds used during construction at rates approved by the Alberta Energy and Utilities Board ("AEUB") for debt and equity capital. Property, plant and equipment in the other subsidiaries include capitalized interest incurred during construction.

Certain regulated additions are made with the assistance of non-refundable cash contributions from customers when the estimated revenue is less than the cost of providing service or where special equipment is needed to supply the customers' specific requirements. These contributions are amortized on the same basis as, and offset the depreciation charge of, the assets to which they relate.

Depreciation is provided on assets on a straight-line basis over their estimated useful lives. Depreciation rates for regulated assets, excluding Alberta Power (2000)'s generating plants, are approved by the AEUB and include a provision for future removal costs and site restoration costs (see the accounting policy for asset retirement obligations below). On retirement of these depreciable regulated assets, the accumulated depreciation is charged with the cost of the retired unit, net disposal costs and site restoration costs.

Property, plant and equipment and intangible assets with finite lives are tested for recoverability whenever events or changes in circumstances indicate a possible impairment. An impairment of property, plant and equipment and intangible assets with finite lives is recognized in earnings when the asset's carrying value exceeds the total cash flows expected from its use and eventual disposition. The impairment loss is then calculated as the difference between the asset's carrying value and its fair value, which is determined using present value techniques.

Deferred Financing Charges

Issue costs of long term debt are amortized over the life of the debt, issue costs of preferred shares relating to regulated operations are amortized over the expected life of the issue and issue costs of preferred shares relating to other subsidiaries are charged to retained earnings. Unamortized premiums and issue costs of redeemed long term debt and preferred shares relating to regulated operations are amortized over the life of the issue funding the redemption.

Deferred Availability Incentives

Under the terms of the PPA's, the Corporation is subject to an incentive/penalty regime related to generating unit availability. Incentives are paid to the Corporation by the PPA counterparties for availability in excess of predetermined targets, whereas penalties are paid by the Corporation to the PPA counterparties when the availability targets are not achieved.

Accumulated incentives in excess of accumulated penalties are deferred. For any of the individual PPA's, should accumulated incentives plus estimated future incentives exceed accumulated penalties plus estimated future penalties, the excess will be amortized to revenues on a straight-line basis over the remaining term of the PPA's. Should accumulated penalties plus estimated future penalties exceed accumulated incentives plus estimated future incentives, the shortfall will be expensed in the year the shortfall occurs.

Asset Retirement Obligations

Asset retirement obligations are legal obligations associated with the retirement of tangible long lived assets. To the extent that they can be quantified, these obligations are measured and recognized at fair value, which is determined using present value techniques.

An asset retirement obligation is recorded as a liability in deferred credits, with a corresponding increase to property, plant and equipment. The liability is accreted over the estimated time period until settlement of the obligation, with the accretion expense included in depreciation and amortization. The asset is depreciated over its estimated useful life.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Asset retirement obligations for regulated natural gas and electric transmission and distribution assets are not recognized as the Corporation expects to use the assets in service for an indefinite period. As such, no final removal date can be determined and, consequently, a reasonable estimate of the related retirement obligations cannot be made at this time. Asset retirement obligations have been recorded for the regulated generating plants of Alberta Power (2000) and other generating plants and natural gas liquids extraction and processing plants.

Effective January 1, 2006, the Corporation retroactively adopted the Canadian Institute of Chartered Accountant's ("CICA") Emerging Issues Abstract regarding conditional asset retirement obligations. This abstract requires an entity to record a liability for an asset retirement obligation where the timing and/or method of settlement are conditional upon the occurrence of a future event that may or may not be within the control of the entity. Adoption of this abstract had no effect on the consolidated financial statements for the year ended December 31, 2006.

Long Term Debt Due Within One Year

When the Corporation intends to refinance long term debt due within one year on a long term basis and there is a written undertaking from an underwriter to act on the Corporation's behalf with respect thereto, or sufficient capacity exists under long term bank loan agreements to issue commercial paper or assume bank loans, then long term debt due within one year is classified as long term.

Hedging

In conducting its business, the Corporation uses various instruments, including forward contracts, swaps and options, to manage the risks arising from fluctuations in exchange rates, interest rates and commodity prices. All such instruments are used only to manage risk and not for trading purposes.

The Corporation designates each derivative instrument as a hedge of specific assets or liabilities on the balance sheet or specific firm commitments or anticipated transactions. The Corporation also assesses, both at the hedge's inception and on an ongoing basis, whether the derivative instruments that are used in hedging transactions are effective in offsetting changes in fair values or cash flows of the hedged items.

Payments or receipts on derivative instruments that are designated and effective as hedges are recognized concurrently with, and in the same financial category as, the hedged item.

If a derivative instrument is terminated or ceases to be effective as a hedge prior to maturity, the gain or loss at that date is deferred and recognized in income concurrently with the hedged item. Subsequent changes in the value of the derivative instrument are reflected in income. If the designated hedged item is sold, extinguished or matures prior to the termination of the related derivative instrument, the gain or loss at that date on such derivative instrument is recognized in income.

Employee Future Benefits

The Corporation accrues for its obligations under defined benefit pension and other post employment benefit plans. Costs of these benefits are determined using the projected benefits method prorated on service and reflects management's best estimates of investment returns, wage and salary increases, age at retirement and expected health care costs.

Pension plan assets at the end of the year are reported at market value. The expected long term rate of return on plan assets is determined at the beginning of the year on the basis of the long bond yield rate at the beginning of the year plus an equity and management premium that reflects the plan asset mix. Expected return on plan assets for the year is calculated by applying the expected long term rate of return to the market related value of plan assets, which is the average of the market value of plan assets at the end of the preceding three years.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Accrued benefit obligations at the end of the year are determined using a discount rate that reflects market interest rates on high quality corporate bonds that match the timing and amount of expected benefit payments.

Experience gains and losses and the effect of changes in assumptions in excess of 10% of the greater of the accrued benefit obligations or the market value of plan assets, adjustments resulting from plan amendments and the net transitional liability or asset, which arose upon the adoption in 2000 of the current accounting standard, are amortized over the estimated average remaining service life of employees.

Pursuant to an AEUB decision effective January 1, 2000, the regulated operations, excluding Alberta Power (2000), are required to expense contributions for other post employment benefit and certain other defined benefit pension plans as paid. The differences between the amounts accrued and paid are deferred in non-current regulatory assets and liabilities.

Employer contributions to the defined contribution pension plans are expensed as paid.

Stock Based Compensation Plans

The Corporation expenses stock options granted on and after January 1, 2002; no compensation expense is recorded for stock options granted prior to January 1, 2002 as permitted by GAAP. The Corporation determines the fair value of the options on the date of grant using an option pricing model and recognizes the fair value over the vesting period of the options granted as compensation expense and contributed surplus. Contributed surplus is reduced as the options are exercised and the amount initially recorded in contributed surplus is credited to Class A and Class B share capital.

No compensation expense is recognized when share appreciation rights are granted. Prior to vesting, compensation expense arising from an increase or decrease in the market price of the shares over the base value of the rights is accrued equally over the remaining months to the date of vesting. After that date, compensation expense arising from an increase or decrease in the market price of the shares is recognized monthly in earnings.

Effective January 1, 2006, the Corporation retroactively adopted the CICA Emerging Issues Abstract regarding stock based compensation for employees eligible to retire before the vesting date. This abstract requires an entity to recognize the compensation cost attributable to such an award over the period from grant date to the date the employee becomes eligible to retire. Since the Corporation does not have stock based compensation plans that contain such provisions, adoption of this abstract had no effect on the consolidated financial statements for the year ended December 31, 2006.

Foreign Currency Translation

Assets and liabilities of self-sustaining foreign operations are translated into Canadian dollars at the rate of exchange in effect at the balance sheet date and revenues and expenses are translated at the average monthly rates of exchange during the year. Gains or losses on translation of self-sustaining foreign operations are included in the foreign currency translation adjustment in share owners' equity.

Monetary assets and liabilities of integrated foreign operations are translated into Canadian dollars at the rate of exchange in effect at the balance sheet date, non-monetary assets and liabilities are translated at rates of exchange in effect when the assets were acquired or liabilities incurred, and revenues and expenses are translated at the average monthly rates of exchange during the year. Gains or losses on translation of integrated foreign operations are recognized in earnings.

Transactions undertaken by Canadian operations that are denominated in foreign currencies are translated into Canadian dollars at the rate of exchange in effect at the transaction date.

2. ACCOUNTING FOR RATE REGULATED OPERATIONS

Nature and economic effects of rate regulation

ATCO Electric, ATCO Gas and ATCO Pipelines (the "utilities") are regulated primarily by the AEUB, which administers acts and regulations covering such matters as rates, financing, accounting, construction, operation and service area.

The generating plants of Alberta Power (2000) were regulated by the AEUB until December 31, 2000 but are now governed by legislatively mandated PPA's that were approved by the AEUB. These plants are included in regulated operations primarily because the PPA's are designed to allow the owners of generating plants constructed before January 1, 1996 to recover their forecast fixed and variable costs and to earn a return at the rate specified in the PPA's. The plants will become deregulated upon the earlier of one year after the expiry of a PPA or a decision to continue to operate the plant. Each PPA is to remain in effect until the earlier of the last day of the estimated life of the related generating plant and December 31, 2020.

The utilities are subject to a cost of service regulatory mechanism under which the AEUB establishes the revenues required (i) to recover the forecast operating costs, including depreciation and amortization and income taxes, of providing the regulated service, and (ii) to provide a fair and reasonable return on utility investment, or rate base. Whereas actual operating conditions may vary from forecast, actual returns achieved can differ from approved returns.

Rate base for each utility is the aggregate of the AEUB approved investment in property, plant and equipment, less accumulated depreciation, plus an allowance for working capital. Rate base also excludes no-cost capital, which consists of unamortized contributions by utility customers for extensions to plant. The utilities earn a return on rate base intended to meet the cost of the debt and preferred share components of rate base and to provide share owners with a fair return on the common equity component of rate base.

The AEUB approves rates of return for the debt and preferred share components of rate base based on the actual or forecast weighted average cost of each utility's debt and preferred shares. On July 2, 2004, the AEUB established a standardized approach for determining the rate of return on common equity for each utility regulated by the AEUB. This rate of return will be adjusted annually by 75% of the change in long term Government of Canada bond yield as forecast in the November Consensus Forecast, adjusted for the average difference between the 10 year and 30 year Government of Canada bond yields for the month of October as reported in the National Post. In January 2006, the AEUB clarified that the generic return on equity determined on an annual basis in accordance with the generic cost of capital decision should apply to each year of the test period in the utilities' applications. If no rate applications are filed for a particular year, then there will be no adjustment to the common equity rate of return for that year.

The AEUB also established the capital structure for each utility and determined that any proposed changes to the approved capital structure which result from a material change in the investment risk of a utility will be addressed at utility specific rate applications.

Under the cost of service methodology, the utilities seek approval for their revenue requirement either through submission of general rate applications to the AEUB or a negotiated settlement process with interested parties. In the latter case, the AEUB monitors the negotiated settlement process and approves any agreement that is reached. The AEUB may approve interim rates or approve recovery of costs on a placeholder basis, subject to final determination.

Financial statement effects of rate regulation

Certain items in these consolidated financial statements are accounted for differently than they would be in the absence of rate regulation. CICA recommendations do not require that assets and liabilities arising from rate regulation be recognized and measured in accordance with the primary sources of GAAP.

2. ACCOUNTING FOR RATE REGULATED OPERATIONS (CONTINUED)

Where regulatory decisions dictate, the utilities defer certain costs or revenues as assets or liabilities on the balance sheet and record them as expenses or revenues in the earnings statement as they collect or refund amounts through future customer rates. Any adjustments to these deferred amounts are recognized in earnings in the period that the AEUB renders a subsequent decision.

Circumstances in which rate regulation affects the accounting for a transaction or event are described below. For these regulatory items, the expected recovery or settlement period, or likelihood of recovery or settlement, is affected by risks and uncertainties relating to the ultimate authority of the regulator in determining the item's treatment for rate setting purposes, and, unless specifically indicated, is indeterminate.

The regulatory assets and liabilities comprise the following:

	2006	2005
Regulatory assets – current:		
Deferred hearing costs	**$ -**	$ 8.8
Deferred electricity costs	**1.7**	-
Other regulatory assets	**11.6**	10.3
	$ 13.3	$ 19.1
Regulatory assets – non-current:		
Regulatory other post employment benefits asset (Note 20)	**$ 27.6**	$ 22.0
Deferred electricity costs	**7.1**	5.4
Deferred hearing costs	**1.4**	1.6
Reserves for injuries and damages	**2.0**	5.4
Other regulatory assets	**5.1**	0.6
	$ 43.2	$ 35.0
Regulatory liabilities – current:		
Deferred electricity cost recoveries	**$ -**	$ 4.0
Reserves for injuries and damages	**-**	0.8
Other regulatory liabilities	**0.5**	1.6
	$ 0.5	$ 6.4
Regulatory liabilities – non-current:		
Regulatory pension liability (Note 20)	**$118.7**	$139.4
Deferred royalty credits	**19.7**	18.1
Deferred electricity cost recoveries	**6.2**	-
Deferred hearing costs	**0.4**	2.6
Reserves for injuries and damages	**2.8**	0.8
Other regulatory liabilities	**1.0**	1.0
	$148.8	$161.9

Employee future benefits

The Corporation accrues for its obligations under defined benefit pension and other post employment benefit plans. The regulatory asset (liability) reflects an AEUB decision, effective January 1, 2000, to record costs of employee future benefits in the utilities when paid rather than accrued. The variances between the amounts paid and accrued for each of the defined benefit pension plans and the other post employment benefit plans will vary depending on the performance of plan assets and the actuarial valuations of plan obligations. These variances will be deferred until the plans are paid, settled or terminated.

GAAP requires that the variances between the amounts accrued and paid be recognized as an expense or reduction in expense in the period in which they are accrued. Consequently, defined benefit pension plan cost in 2006 would have been $19.5 million higher (2005 – $1.6 million lower), and other post employment benefit plan cost in 2006 would have been $3.5 million higher (2005 – $3.3 million higher), in the absence of rate regulation.

2. ACCOUNTING FOR RATE REGULATED OPERATIONS (CONTINUED)

Upon the adoption of the current accounting standard in 2000, the utilities had recorded deferred pension assets of $23.0 million. The utilities have been earning an AEUB approved rate of return on these assets through customer rates as the assets form part of the utilities' AEUB approved rate base. In the absence of rate regulation, the utilities would not be able to earn a return on these assets. Consequently, revenues in 2006 would have been $1.7 million lower (2005 – $2.1 million lower). On October 11, 2006, the AEUB issued a decision that approved recovery of these assets for a nine-year period commencing January 1, 2005 and permitted the utilities to continue to earn an AEUB approved rate of return on the unrecovered portion of these assets over the recovery period. In 2006, the utilities amortized $5.1 million (2005 – nil) of the deferred pension asset.

Deferred electricity costs (recoveries)

Variances between ATCO Electric's actual and forecast transmission access payments may arise due to changes in tariffs charged by the Alberta Power Pool. The amount included in customer rates is based on forecast cost. Revenues are adjusted for changes in tariffs, and the variances are deferred until approval from the AEUB is obtained for refund to or collection from customers, which is expected to occur in the following year. GAAP requires that revenues be based on the rates approved by the AEUB and not adjusted for variances between forecast and actual costs.

In Alberta, major transmission capital projects are planned by the Alberta Power Pool and directly assigned to one of the transmission facility owners in the province. Revenue requirement includes a return on forecast rate base. Whereas actual capital costs may vary from forecast capital costs, variances may arise between the return on forecast rate base and the return on actual rate base. Revenues are adjusted for these variances, and the variances are deferred until approval from the AEUB is obtained for refund to or collection from the Alberta Power Pool, which is expected to occur in the following year. GAAP requires that revenues be based on the rates approved by the AEUB and not adjusted for variances between the returns on forecast and actual rate base.

Consequently, revenues in 2006 would have been $1.2 million lower (2005 – $23.4 million lower) in the absence of rate regulation.

Deferred hearing costs

The utilities incur hearing costs on an ongoing basis associated with various AEUB regulatory proceedings. These costs are comprised primarily of legal and consulting expenses incurred by the utilities in addition to costs incurred by intervenor groups that have been reimbursed by the utilities as directed by the AEUB. Hearing costs are deferred to the balance sheet and are expensed using AEUB approved annual amounts that are collected through customer rates. Variances between the approved annual amounts and actual costs incurred are deferred until the next general rate application or until a specific application is made to the AEUB requesting recovery from or refund to customers. GAAP requires that hearing costs be expensed in the period in which they are incurred. Consequently, expenses in 2006 would have been $6.8 million lower (2005 – $4.0 million higher) in the absence of rate regulation.

Reserves for injuries and damages

The AEUB has approved the use of reserves for injuries and damages by the utilities as a means of self-insurance. The reserves for injuries and damages are established based on annual amounts approved by the AEUB to be expensed by each utility and collected through customer rates. Variances between the approved annual amounts and actual costs incurred are deferred until the following general rate application or until a specific application is made to the AEUB requesting recovery from or refund to customers. GAAP requires that claims be expensed in the period in which they are incurred. Consequently, expenses in 2006 would have been $3.6 million lower (2005 – $1.1 million lower) in the absence of rate regulation.

2. ACCOUNTING FOR RATE REGULATED OPERATIONS (CONTINUED)

For Alberta Power (2000), reserves for injuries and damages are recoverable under the terms of the PPA's on a straight line basis through 2008. GAAP requires that claims be expensed in the period in which they are incurred. Consequently, expenses in 2006 would have been $1.0 million lower (2005 – $1.0 million lower) in the absence of rate regulation.

Deferred royalty credits

Under the terms of PPA's, the compensation for certain royalties incurred by Alberta Power (2000) for coal supply are averaged over the term of each PPA. As such, royalty costs incurred are deferred and expensed on the same average cost basis as reflected in the underlying PPA revenues. GAAP requires that royalty costs be expensed in the period in which they are incurred. Consequently, expenses in 2006 would have been $1.6 million lower (2005 – $4.0 million lower) in the absence of rate regulation.

Other regulatory assets and liabilities

Other regulatory assets and liabilities include the following:

a) ATCO Gas has received AEUB approval to defer:
   i) Bad debt and collection agency fees incurred after June 1, 2004 related to billings prior to that date and associated late payment charges net of bad debt recoveries of $(0.1) million (2005 – $1.4 million);
   ii) Charges from the Government of Alberta for funding of the office of the Utilities Consumer Advocate and the Consumer Protection and Consumer Choice Campaign, net of AEUB approved recoveries from customers, of $(0.6) million (2005 – $1.0 million); and,
   iii) Removal and abandonment costs related to previously disposed of production properties, net of AEUB approved recoveries from customers, of nil (2005 – $5.0 million).

   Variances between the approved annual amounts and actual costs are deferred until the following general rate application or until a specific application is made to the AEUB requesting recovery from or refund to customers. GAAP requires that these net costs be expensed in the period in which they are incurred. Consequently, expenses in 2006 would have been $8.1 million lower (2005 – $2.1 million higher) in the absence of rate regulation. Liabilities of $0.7 million are included in non-current regulatory liabilities (2005 – $6.9 million in current regulatory assets and $0.5 million in non-current regulatory assets).

b) In October 2005, ATCO Gas filed an application with the AEUB to approve the sale of its Red Deer Operating Centre. In December 2005, the AEUB approved the sale and deferred its decision on the distribution of net proceeds of $1.0 million until the Supreme Court of Canada rendered a judgment in the appeal regarding the Calgary Stores Block disposition and allocation of proceeds thereon. The Supreme Court of Canada rendered its decision on the Calgary Stores Block matter on February 9, 2006 and the AEUB complied with that decision on August 11, 2006. Subsequently, ATCO Gas submitted a filing to the AEUB to approve the allocation of the net proceeds from the sale of the Red Deer Operating Centre. On December 13, 2006, the AEUB issued a decision approving the distribution of the proceeds to ATCO Gas. GAAP requires that gains and losses related to asset dispositions be recognized in the period the disposition was made. Consequently, revenues in 2006 would have been $1.0 million lower (2005 – $1.0 million higher) in the absence of rate regulation.

c) ATCO Pipelines has received AEUB approval to defer the variances between actual and AEUB approved forecast revenues and costs associated with the movement (receipt or delivery) of natural gas between ATCO Pipelines' system and other connected pipeline systems. ATCO Pipelines expects that the recovery of these deferral accounts will occur in the next general rate application. GAAP requires that actual revenues and costs be recognized in the period in which they are earned or incurred. Consequently, revenues in 2006 would have been $0.9 million higher (2005 – $0.1 million lower) and expenses would have been $0.6 million lower (2005 – $1.6 million lower) in the absence of rate regulation. Assets of $2.7 million and $0.2 million (2005 – $2.2 million and nil) are included in current regulatory assets and non-current regulatory assets, respectively, and liabilities of $0.5 million and $0.3 million (2005 – $1.6 million and nil) are included in current regulatory liabilities and non-current regulatory liabilities, respectively.

2. ACCOUNTING FOR RATE REGULATED OPERATIONS (CONTINUED)

d) ATCO Pipelines has received AEUB approval to establish a deferral account for the Salt Cavern Storage facility to collect (i) the revenue requirements for return on rate base and associated income taxes related to the necessary working capital for the natural gas in storage, and (ii) the gains or losses associated with the sale of natural gas in the market upon withdrawal from storage. ATCO Pipelines is required to submit an application to the AEUB, either separately or in conjunction with a general rate application for that particular year, requesting recovery from or refund to customers of the deferral amount should the deferral account exceed $2.0 million at the end of the annual injection/withdrawal cycle on March 31 of a particular year. GAAP requires that actual revenues and costs be recognized in the period in which they are earned or incurred. Consequently, revenues in 2006 would have been $2.6 million lower (2005 – $1.2 million lower) in the absence of rate regulation. Assets of $3.7 million are included in non-current regulatory assets (2005 – $1.2 million in current regulatory assets) in the balance sheet.

e) In 2006, ATCO Pipelines received AEUB approval to establish deferral accounts to collect the costs and revenues arising from load balancing transactions. Load balancing requires the purchase or sale of natural gas to maintain appropriate operating pressures on ATCO Pipelines' North and South transmission pipeline systems. Should the deferral account for either North or South exceed $2.0 million, ATCO Pipelines may submit an application to the AEUB requesting recovery from or refund to customers of that particular deferral amount. GAAP requires that actual revenues and costs be recognized in the period in which they are earned or incurred. Consequently, expenses in 2006 would have been $8.9 million higher in the absence of rate regulation. Assets of $8.9 million are included in current regulatory assets in the balance sheet.

Other items affected by rate regulation

The AEUB permits an allowance for funds used ("AFU"), based on each utility's weighted average cost of capital, to be included in rate base. AFU is also included in the cost of property, plant and equipment for financial reporting purposes, and is depreciated as part of the total cost of the related asset, based on the expectation that depreciation expense, including the AFU component, will be approved for inclusion in future customer rates. Since AFU includes preferred share and common equity components, it exceeds the amount allowed to be capitalized in similar circumstances in the absence of rate regulation.

The utilities and the generating plants of Alberta Power (2000) follow the method of accounting for income taxes that is consistent with the method of determining the income tax component of its rates. When future income taxes are not included in the income tax component of current rates, such future income taxes are not recognized to the extent that they will be recovered from customers through inclusion in future rates. GAAP requires the recognition of all future income tax liabilities and future tax assets in the absence of rate regulation (see Note 7).

3. TRANSFER OF RETAIL ENERGY SUPPLY BUSINESSES

On May 4, 2004, ATCO Gas and ATCO Electric transferred their retail energy supply businesses to Direct Energy Marketing Limited and one of its affiliates (collectively "DEML"), a subsidiary of Centrica plc. Proceeds of the transfer were $90 million, of which $45 million was paid at closing, and the remainder was paid on May 4, 2005. ATCO Gas and ATCO Electric continue to own and operate the natural gas and electricity distribution systems used to deliver energy.

ATCO Pipelines, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical did not participate in this transfer and continue to purchase natural gas and electricity for sale to customers. In addition, the AEUB issued a decision that directed ATCO Gas to continue to reserve for the benefit of utility customers 16.7 petajoules of storage capacity at its Carbon storage facility for the 2004/2005 storage year, which ended on March 31, 2005, and issued a decision that terminated ATCO Pipelines' obligation to purchase natural gas for sale to customers effective October 31, 2005.

3. TRANSFER OF RETAIL ENERGY SUPPLY BUSINESSES (CONTINUED)

Although ATCO Gas and ATCO Electric transferred to DEML certain retail functions, including the supply of natural gas and electricity to customers and billing and customer care functions, the legal obligations of ATCO Gas and ATCO Electric remain if DEML fails to perform. In certain events (including where DEML fails to supply natural gas and/or electricity and ATCO Gas and/or ATCO Electric are ordered by the AEUB to do so), the functions will revert to ATCO Gas and/or ATCO Electric with no refund of the transfer proceeds to DEML by ATCO Gas and/or ATCO Electric.

Centrica plc, DEML's parent, has provided a $300 million guarantee supported by a $235 million letter of credit in respect of DEML's obligations to ATCO Gas, ATCO Electric and ATCO I-Tek Business Services in respect of the ongoing relationships contemplated under the transaction agreements. However, there can be no assurance that the coverage under these agreements will be adequate to cover all of the costs that could arise in the event of a reversion of such functions.

Canadian Utilities Limited has provided a guarantee of ATCO Gas', ATCO Electric's and ATCO I-Tek Business Services' payment and indemnity obligations to DEML contemplated under the transaction agreements.

4. REGULATORY MATTERS

On March 17, 2006, ATCO Electric received a decision on its general tariff application for 2005 and 2006 which was filed with the AEUB in May 2005. The decision establishes the amount of revenue ATCO Electric can recover through its rates for electric distribution and transmission service provided to its customers for 2005 and 2006. In July and September 2005, the AEUB had approved interim refundable rates for distribution and transmission operations, respectively; revenues associated with these interim refundable rates were recorded in 2005. The impact of the decision for 2005 reduced earnings by $1.3 million and was recorded in the first quarter of 2006. The impact of the decision for the full year 2006, as compared to the decision for the full year 2005, further reduced earnings by $1.6 million. The decision also confirmed the return on common equity as determined by the AEUB's standardized rate of return methodology. The rate of return on common equity was 9.5% in 2005 and is 8.93% in 2006.

On January 27, 2006, ATCO Gas received a decision on its general rate application which was filed with the AEUB in May 2005 for the 2005, 2006 and 2007 test years. The decision establishes the amount of revenue ATCO Gas can recover through distribution rates for natural gas distribution service to its customers over the period of 2005 to 2007. The decision also approved the return on common equity as determined by the AEUB's standardized rate of return methodology. The rate of return on common equity was 9.5% in 2005, is 8.93% in 2006, and will be 8.51% for 2007. The final impact of the decision will not be known until a subsequent regulatory process is finalized. A decision from the AEUB with respect to a second regulatory process that was pending at the end of 2005 was received on October 11, 2006; the effect of this decision on the earnings of the Corporation was not material.

The Corporation has a number of other regulatory filings and regulatory hearing submissions before the AEUB for which decisions have not been received. The outcome of these matters cannot be determined at this time.

5. TXU EUROPE SETTLEMENT

On November 19, 2002, an administration order was issued by an English Court against TXU Europe Energy Trading Limited ("TXU Europe") which had a long term "off take" agreement for 27.5% of the power produced by the 1,000 megawatt Barking generating plant in London, England, in which the Corporation, through Barking Power, has a 25.5% equity interest. Barking Power had filed a claim for damages for breach of contract related to TXU Europe's obligations to purchase 27.5% of the power produced by the Barking generating plant. Following negotiations with the administrators, an agreement was reached with respect to Barking Power's claim.

5. TXU EUROPE SETTLEMENT (CONTINUED)

Barking Power received a total of four distributions in settlement of its claim: a first distribution of £112.3 million (approximately $257 million) on March 30, 2005, of which the Corporation's share was $65.4 million; a second distribution of £32.2 million (approximately $69.6 million) on August 2, 2005, of which the Corporation's share was $17.7 million; a third distribution of £31.8 million (approximately $65.2 million) on January 19, 2006, of which the Corporation's share was $16.6 million; and a final distribution of £3.0 million (approximately $6.2 million) on July 20, 2006, of which the Corporation's share was $1.6 million. Income taxes of approximately $28.1 million relating to the distributions have been paid. Income taxes of approximately $0.4 million relating to the final distribution will be paid in 2007 as part of the Corporation's normal tax installments.

Based on the foreign currency exchange rate in effect at March 30, 2005, the Corporation's share of this settlement is expected to generate earnings after income taxes of approximately $69 million, which will be recognized over the remaining term of the TXU Europe contract to September 30, 2010, at approximately $11 million per year. These earnings will be dependent upon foreign currency exchange rates in effect at the time that the earnings are recognized.

6. INTEREST AND OTHER INCOME

	2006	2005
Interest	**$39.3**	$29.0
Allowance for funds used by regulated operations	**9.3**	7.0
Gains on dispositions of property, plant and equipment	**8.3**	1.7
Other income (expense)	**1.6**	(1.1)
	$58.5	$36.6

7. INCOME TAXES

The income tax provision differs from that computed using the statutory tax rates for the following reasons:

	2006		2005	
Earnings before income taxes	**$526.8**	**%**	$477.0	%
Income taxes, at statutory rates	**$208.0**	**39.5**	$193.8	40.6
Federal general tax reduction [1]	**(23.2)**	**(4.4)**	(18.1)	(3.8)
Manufacturing and processing tax credit	**(7.7)**	**(1.5)**	(7.5)	(1.6)
Resource allowance	**(1.6)**	**(0.3)**	(2.8)	(0.6)
Crown royalties and other non-deductible Crown payments	**0.7**	**0.1**	1.1	0.2
Foreign tax rate variance	**(7.6)**	**(1.4)**	(6.2)	(1.3)
Non-deductible interest on foreign financing	**1.3**	**0.3**	1.4	0.3
Large Corporations Tax	**-**	**-**	7.8	1.7
Change in future income taxes resulting from reduction in tax rates	**(12.2)**	**(2.3)**	-	-
Change in method of accounting for future income taxes in certain regulated operations	**(4.0)**	**(0.8)**	-	-
Unrecorded future income taxes relating to regulated operations	**2.5**	**0.5**	1.0	0.2
H.R. Milner income tax reassessment	**7.4**	**1.4**	-	-
Other	**3.5**	**0.6**	5.1	1.1
	167.1	**31.7**	175.6	36.8
Current income taxes	**183.0**		185.8	
Future income taxes (recoveries)	**$ (15.9)**		$ (10.2)	

(1) *The federal general tax reduction of 7% is applicable to earnings that have not otherwise benefited from the manufacturing and processing tax credit and/or the resource allowance. An additional federal tax reduction of 5% (2005 – 3%) is applicable to earnings that have benefited from the resource allowance.*

7. INCOME TAXES (CONTINUED)

The future income tax liabilities (assets) comprise the following:

	2006	2005
Property, plant and equipment	**$212.2**	$222.7
Deferred assets and liabilities	**(17.1)**	(18.3)
Tax loss carryforwards	**(0.1)**	(0.3)
Other	**-**	0.3
	195.0	204.4
Less: Amounts included in current future income taxes	**0.3**	4.1
	$194.7	$200.3

At December 31, 2006, unrecorded future income tax liabilities of the regulated operations amounted to $141.3 million and unrecorded future income tax assets of other operations amounted to $0.5 million. The liabilities include $14.6 million in respect of Alberta Power (2000)'s generating plants, which will be recovered through future payments received in respect of the PPA's.

In 2006, the Canada Revenue Agency ("CRA") issued a reassessment for Alberta Power (2000)'s 2001 taxation year. The CRA's reassessment treats the proceeds received from the sale of the H.R. Milner generating plant to the Alberta Balancing Pool as income rather than as a sale of an asset. The Corporation has made submissions to the CRA opposing the CRA's position. The impact of the reassessment is a $12.4 million increase in interest and income tax expense, a $12.4 million decrease in earnings and a $28.8 million payment associated with the tax and interest assessed. It is expected that $16.4 million of this cash payment will be recovered by reducing income taxes payable through higher capital cost allowance claims. Due to the uncertainty as to whether the reassessment will ultimately be resolved in the Corporation's favour, the Corporation reduced earnings by $12.4 million in 2006.

There are tax loss carryforwards of $0.4 million for Canadian subsidiary corporations and $7.6 million for a foreign subsidiary corporation for which no tax benefit has been recorded. The losses for Canadian subsidiary corporations begin to expire in 2010 and the losses for the foreign subsidiary corporation do not expire.

Income taxes paid amounted to $187.0 million (2005 — $178.6 million).

8. PURCHASE OF CLASS A SHARES AND OTHER DIRECT CHARGES TO RETAINED EARNINGS

	2006	2005
Purchase of Class A shares	**$64.4**	$7.5
Purchase of ATCO Európa Szerkezetgyártó és Kereskedelmi Kft. (Note 19)	**0.3**	-
	$64.7	$7.5

9. PROPERTY, PLANT AND EQUIPMENT

	Composite Depreciation Rates	2006 Cost	2006 Accumulated Depreciation	2005 Cost	2005 Accumulated Depreciation
Utilities	3.7%	**$6,490.4**	**$2,411.1**	$6,022.0	$2,240.8
Power Generation	3.2%	**2,853.7**	**1,026.1**	2,753.9	921.4
Global Enterprises	9.2%	**269.5**	**140.8**	270.3	127.1
Other	4.7%	**26.7**	**6.7**	27.7	6.1
		$9,640.3	**3,584.7**	$9,073.9	3,295.4
Property, plant and equipment less accumulated depreciation			**6,055.6**		5,778.5
Unamortized contributions by utility customers for extensions to plant			**629.5**		569.8
			$5,426.1		$5,208.7

9. PROPERTY, PLANT AND EQUIPMENT (CONTINUED)

Accumulated depreciation includes amounts provided for future removal and site restoration costs, net of salvage value, of $374.6 million (2005 – $323.6 million).

Composite depreciation rates reflect total depreciation in the year as a percentage of mid-year cost, excluding construction work-in-progress of $114.2 million (2005 – $91.1 million) and non-depreciable assets of $52.3 million (2005 – $41.3 million).

10. OTHER ASSETS

	2006	2005
Accrued pension asset (Note 20)	**$157.1**	$192.2
Security deposits for debt	**22.8**	20.0
Deferred financing charges (1)	**25.0**	25.4
Other (2)	**24.8**	31.5
	$229.7	$269.1

(1) *Amortization of deferred financing charges, which was recorded in interest expense, amounted to $2.8 million (2005 – $2.8 million).*

(1) *Amortization of certain other assets, which was recorded in depreciation and amortization, amounted to $14.9 million (2005 – $5.9 million).*

11. CREDIT LINES

At December 31, 2006, the Corporation has the following credit lines that enable it to obtain financing for general business purposes:

		2006			2005	
	Total	**Used**	**Available**	Total	Used	Available
Long term committed	**$326.0**	**$47.4**	**$278.6**	$326.0	$11.9	$314.1
Short term committed	**600.0**	**14.0**	**586.0**	600.0	-	600.0
Uncommitted	**69.1**	**7.1**	**62.0**	69.1	8.3	60.8
	$995.1	**$68.5**	**$926.6**	$995.1	$20.2	$974.9

Of the $68.5 million used at December 31, 2006, $47.0 million is included in long term debt and $21.5 million represents outstanding letters of credit.

12. LONG TERM DEBT AND NON-RECOURSE LONG TERM DEBT

Long term debt

	2006	2005
CU Inc. debentures – unsecured		
2001 4.84% due November 2006	$ -	$ 175.0
2002 4.801% due November 2007	50.0	50.0
2000 6.97% due June 2008	100.0	100.0
1989 Series 10.20% due November 2009	125.0	125.0
1990 Series 11.40% due August 2010	125.0	125.0
2000 7.05% due June 2011	100.0	100.0
2004 5.096% due November 2014	100.0	100.0
2002 6.145% due November 2017	150.0	150.0
2004 5.432% due January 2019	180.0	180.0
1999 Series 6.8% due August 2019	300.0	300.0
1990 Second Series 11.77% due November 2020	100.0	100.0
2006 4.801% due November 2021	160.0	-
1991 Series 9.92% due April 2022	125.0	125.0
1992 Series 9.40% due May 2023	100.0	100.0
2004 5.896% due November 2034	200.0	200.0
2005 5.183% due November 2035	185.0	185.0
2006 5.032% due November 2036	160.0	-
Canadian Utilities Limited debentures – unsecured		
2002 6.14% due November 2012	100.0	100.0
	2,360.0	2,215.0
ATCO Midstream Ltd. credit facility, at BA rates, due June 2011, unsecured (1)	25.0	-
ATCO Power Canada Ltd. credit facility, at BA rates, due August 2011, secured by a pledge of cash (1)	22.0	11.5
Other long term obligation, at 5.0%, due June 2007, unsecured	4.5	4.5
	$ 2,411.5	$ 2,231.0

Non-recourse long term debt

	2006	2005
Barking Power Limited project financing, payable in British pounds:		
At fixed rates averaging 7.95%, due to 2010	$ 52.1	$ 54.7
At LIBOR, due to 2010 (1)	85.5	89.6
Osborne Cogeneration Pty Ltd. project financing, payable in Australian dollars:		
At Bank Bill rates, due to 2013 (1)	1.7	1.8
At 7.3325%, due to 2013 (1)	31.8	34.4
ATCO Power Alberta Limited Partnership ("APALP") project financing:		
At 7.54% to 2008, at LIBOR thereafter, due to 2016 (1)	2.6	3.8
At 7.317% to 2008, at LIBOR thereafter, due to 2016 (1)	3.6	5.4
At 7.50% to 2011, at LIBOR thereafter, due to 2016 (1)	83.8	87.5
Joffre project financing:		
At 7.286%, due to 2012 (1)	15.6	26.7
At 8.59%, due to 2020	32.0	32.0
Scotford project financing:		
At 5.212%, due to 2008, at BA rates thereafter, due to 2014 (1)	42.8	46.2
At 5.212%, due to 2008, at LIBOR thereafter, due to 2014 (1)	10.7	11.6
At 7.93%, due to 2022	26.1	26.9

12. LONG TERM DEBT AND NON-RECOURSE LONG TERM DEBT (CONTINUED)

Non-recourse long term debt (continued)

	2006	2005
Muskeg River project financing:		
At 5.287%, due 2007, at BA rates thereafter, due to 2014 (1)	**40.8**	44.4
At BA rates, due to 2014 (1)	**0.1**	0.3
At 7.56%, due to 2022	**29.4**	31.2
Brighton Beach project financing:		
At 5.8367%, due 2009, at BA or Canadian Eurodollar rates thereafter, due to 2019 (1)	**8.9**	9.4
At BA or Canadian Eurodollar rates, due to 2019 (1)	**2.7**	2.5
At 6.575%, due to 2019 (1)	**36.1**	37.8
At 6.924%, due to 2024	**107.8**	110.5
Cory project financing:		
At BA rates, due to 2011 (1)	**0.3**	0.3
At 6.346%, due to 2011 (1)	**2.7**	3.3
At 7.586%, due to 2025	**36.5**	37.4
At 7.601%, due to 2026	**32.4**	33.1
	686.0	730.8
Less: Amounts due within one year	**59.3**	57.0
	$626.7	$673.8

BA – Bankers' Acceptance
LIBOR – London Interbank Offered Rate

(1) The above interest rates have additional margin fees at a weighted average rate of 1.1% (2005 – 1.1%) (Note 21). The margin fees are subject to escalation.

The Corporation has fixed interest rates, either directly or through interest rate swap agreements, on 96% (2005 – 96%) of total long term debt and non-recourse long term debt.

The non-recourse long term debt is secured by charges on the projects' assets and by an assignment of the projects' bank accounts, outstanding contracts and agreements. The book value of the pledged assets and bank accounts at December 31, 2006 was $1,415.2 million (2005 – $1,342.4 million).

Guarantees

Canadian Utilities Limited has provided a number of guarantees related to ATCO Power's obligations under non-recourse loans associated with certain of its projects. These guarantees cover the following items:

a) **Construction liens** – Represents liens currently registered against project assets. Effective September 30, 2005, ATCO Power entered into an indemnity agreement with Brighton Beach Power Ltd. obligating it to cover any cash shortfalls associated with clearing the construction liens registered against the project. This agreement allowed the project to achieve financial completion under the terms of the project financing agreement. The maximum amount of the indemnity is $8.3 million. Canadian Utilities Limited issued a guarantee to Brighton Beach Power Ltd. guaranteeing the payments under the indemnity agreement. The indemnity and the guarantee are reduced as the liens are settled.

12. LONG TERM DEBT AND NON-RECOURSE LONG TERM DEBT (CONTINUED)

b) **Project cash flows** – Represents annual payments related to maintaining base case margins for electricity prices on the merchant power component of the project, being 24 megawatts ("MW") for the Scotford project and 48 MW for the Muskeg River project. These guarantees became effective upon the commercial operation of the plants and exist until 2022, when the project debt is to be fully repaid. The amounts payable under these guarantees will vary each year depending on the pool price received for the merchant power generated. Any payments made to maintain the project base case margins will either be available for distribution to the owners or be applied to mandatory prepayment of the project debt in accordance with the terms of the project financing agreement depending upon the specific operating results of the plant. At December 31, 2006, no amounts were outstanding under the guarantee.

c) **Reserve amounts** – Represents amounts to be set aside for major maintenance and debt service reserves as stipulated in the project's financing agreement. These reserves are intended to be funded with project cash flows. To the extent that project cash flows are insufficient to meet reserve requirements, Canadian Utilities Limited may choose to provide guarantees in lieu of ATCO Power providing security. At December 31, 2006, the amount of the obligations under these guarantees is:

Project	Major Maintenance	Debt Service
APALP project financing	Nil (1)	$6.9
Brighton Beach project financing	Nil (2)	Nil
Cory project financing	Nil (1)	$3.9
Joffre project financing	Nil (3)	$4.7
Muskeg River project financing	Nil (1)	$5.0
Scotford project financing	Nil (1)	$5.6

(1) *No major maintenance reserve required for this financing.*
(2) *Reserve requirements of $0.3 million met with project cash flows.*
(3) *Reserve requirements of $1.0 million met with project cash flows.*

d) **Prepaid operating and maintenance fee** – Should ATCO Power cease to be operator of the APALP generating plants as a result of a termination of the operating agreement, Canadian Utilities Limited has guaranteed the payment of the unamortized portion of the prepaid operating and maintenance fee to APALP, the proceeds of which are to be used to repay project debt in accordance with the project financing agreements. This guarantee, which declines by $1.2 million per year, remains in effect until 2016, when the project debt is to be fully repaid. At December 31, 2006, the maximum value of the guarantee is $30.0 million.

e) **Purchase project assets** – Represents an obligation to purchase the Scotford and Muskeg River projects at a price sufficient to repay any outstanding project debt upon the occurrence of any one of the following very limited events:

(i) where all of the following events have occurred:
- the insolvency of ATCO Power;
- the failure of the project debt lenders to complete a sale of the project pursuant to their security within a fixed period of time; and
- the project purchaser of electricity and steam elects to terminate its purchase contracts due to the insolvency of ATCO Power;

(ii) where the project purchaser of electricity and steam does not remove ATCO Power as operator of the project after an event of default under the project financing agreements in circumstances where such default is either:
- a deliberate or willful breach of a project financing agreement; or
- where ATCO Power has failed to co-operate with the lenders in a sale of the project; and

(iii) where the project purchaser of electricity and steam terminates its purchase contracts for the project as a result of a default by ATCO Power's project minority joint venturers. ATCO Power has the right to cure any such default by acquiring the minority interest which is in default.

These guarantees remain in effect until the project debt is fully repaid. At December 31, 2006, no such events have occurred.

12. LONG TERM DEBT AND NON-RECOURSE LONG TERM DEBT (CONTINUED)

Canadian Utilities Limited has also guaranteed ATCO Power's duties to operate the Barking Power, Scotford and Muskeg River generating plants in accordance with acceptable industry operating standards under the relevant project contracts.

ATCO Power (80%) and ATCO Resources (20%), a wholly owned subsidiary of Canadian Utilities Limited's parent corporation, ATCO Ltd., have a joint venture in the above projects subject to guarantees, excluding Barking Power.

The foregoing guaranteed amounts represent ATCO Power's 80% interest. Canadian Utilities Limited has also guaranteed similar obligations in respect of ATCO Resources' 20% interest. ATCO Ltd. has indemnified and agreed to reimburse Canadian Utilities Limited for any amounts it may be required to pay under these guarantees in respect of ATCO Resources' 20% interest.

To date, Canadian Utilities Limited has not been required to pay any of its guaranteed obligations.

Minimum debt repayments

The minimum annual debt repayments for each of the next five years are as follows:

	Long Term Debt	Non-Recourse Long Term Debt	Total
2007	$ 54.5	$ 59.3	$113.8
2008	100.0	77.9	177.9
2009	125.0	72.4	197.4
2010	125.0	79.4	204.4
2011	147.0	44.8	191.8
	$551.5	$333.8	$885.3

Of the $113.8 million due in 2007, $54.5 million is to be refinanced and is, therefore, excluded from long term debt due within one year in the balance sheet.

Interest expense

Interest expense is as follows:

	2006	2005
Long term debt	**$161.0**	$154.5
Non-recourse long term debt	**49.0**	51.4
Notes payable	**0.3**	-
Bank indebtedness	**1.5**	1.3
Amortization of deferred financing charges	**2.8**	2.8
Interest on H.R. Milner tax reassessment (Note 7)	**8.3**	-
	$222.9	$210.0

Interest paid amounted to $220.8 million (2005 – $207.2 million).

12. LONG TERM DEBT AND NON-RECOURSE LONG TERM DEBT (CONTINUED)

Fair values

Fair values for the above debt, determined using quoted market prices for the same or similar issues, are shown below. Where the market prices are not available, fair values are estimated using discounted cash flow analysis based on the Corporation's current borrowing rate for similar borrowing arrangements.

	2006	2005
Long term debt		
Fixed rate	$2,741.4	$2,656.2
Floating rate	47.0	11.5
	$2,788.4	$2,667.7
Non-recourse long term debt		
Fixed rate	$ 635.3	$ 683.9
Floating rate	90.2	94.5
	$ 725.5	$ 778.4

13. DEFERRED CREDITS

	2006	2005
Accrued other post employment benefits liability (Note 20)	$ 45.1	$ 35.4
Deferred revenues (Note 5)	46.8	59.6
Deferred availability incentives	39.6	59.7
Asset retirement obligations	69.4	62.2
Accrued equipment repairs and maintenance	7.5	8.8
Other	20.6	28.1
	$229.0	$253.8

Deferred availability incentives

Amortization of deferred availability incentives, which was recorded in revenues, amounted to $10.6 million (2005 – $8.9 million).

The amount to be amortized is dependent upon estimates of future generating unit availability and future electricity prices over the term of the PPA's. Each quarter, the Corporation uses these estimates to forecast the incentives to be received from, less penalties to be paid to, the PPA counterparties. These forecasts are added to the accumulated unamortized deferred availability incentives outstanding at the end of the quarter; the resulting total is divided by the remaining term of the PPA to arrive at the amortization for the quarter.

Asset retirement obligations

Changes in asset retirement obligations are summarized below:

	2006	2005
Obligations at beginning of year	$62.2	$34.7
Obligations incurred	3.7	25.4
Accretion expense	3.5	2.1
Obligations at end of year	$69.4	$62.2

The Corporation estimates the undiscounted amount of cash flow required to settle the asset retirement obligations is approximately $131 million, which will be incurred between 2007 and 2052. The discount rates used to calculate the fair value of the asset retirement obligations have a weighted average rate of 5.7%.

14. EQUITY PREFERRED SHARES

Authorized and issued

Authorized: An unlimited number of Series Second Preferred Shares, issuable in series.

Issued:

	Stated Value	Redemption Dates	2006		2005	
			Shares	**Amount**	Shares	Amount
	(dollars)					
Cumulative Redeemable Second Preferred Shares						
5.9% Series Q	$25.00	Open	**2,277,675**	**$ 56.9**	2,277,675	$ 56.9
5.3% Series R	$25.00	Open	**2,146,730**	**53.7**	2,146,730	53.7
6.6% Series S	$25.00	Open	**635,700**	**15.9**	635,700	15.9
5.8% Series W	$25.00	See below	**6,000,000**	**150.0**	6,000,000	150.0
6.0% Series X	$25.00	See below	**6,000,000**	**150.0**	6,000,000	150.0
Perpetual Cumulative Second Preferred Shares						
4.35% Series O	$25.00	December 2, 2011	**1,600,000**	**40.0**	1,600,000	40.0
4.35% Series T	$25.00	December 2, 2011	**1,600,000**	**40.0**	1,600,000	40.0
4.35% Series U	$25.00	December 2, 2011	**800,000**	**20.0**	800,000	20.0
5.25% Series V	$25.00	October 3, 2007	**4,400,000**	**110.0**	4,400,000	110.0
				$636.5		$636.5

The dividends payable on the Series O, T, U, and V preferred shares are fixed until the redemption dates specified above, at which time a new dividend rate may be established by negotiations between Canadian Utilities Limited and the owners of the shares.

Fair values

Fair values for preferred shares determined using quoted market prices for the same or similar issues are $666.8 million (2005 – $669.1 million).

Redemption privileges

The preferred shares, except for Series W and X, are redeemable on the dates specified above at the option of Canadian Utilities Limited at the stated value plus accrued and unpaid dividends.

The Series W preferred shares are redeemable commencing on March 1, 2008 at the stated value plus a 4% premium for the next 12 months plus accrued and unpaid dividends. The redemption premium declines by 1% in each succeeding 12 month period until March 1, 2012.

The Series X preferred shares are redeemable commencing June 1, 2008 at the stated value plus a 4% premium for the next 12 months plus accrued and unpaid dividends. The redemption premium declines by 1% in each succeeding 12 month period until June 1, 2012.

15. CLASS A AND CLASS B SHARES

Authorized and issued

	Class A Non-Voting		Class B Common		Total	
	Shares	Amount	Shares	Amount	Shares	Amount
Authorized:	Unlimited		Unlimited			
Issued and outstanding:						
December 31, 2004	82,740,586	$374.8	44,042,484	$139.5	126,783,070	$514.3
Purchased	(228,600)	(1.0)	-	-	(228,600)	(1.0)
Stock options exercised	338,000	5.8	-	-	338,000	5.8
Converted: Class B to Class A	26,200	0.1	(26,200)	(0.1)	-	-
December 31, 2005	**82,876,186**	**379.7**	**44,016,284**	**139.4**	**126,892,470**	**519.1**
Purchased	**(1,832,200)**	**(8.4)**	**-**	**-**	**(1,832,200)**	**(8.4)**
Stock options exercised	**327,900**	**5.3**	**-**	**-**	**327,900**	**5.3**
Converted: Class B to Class A	**84,800**	**0.3**	**(84,800)**	**(0.3)**	**-**	**-**
December 31, 2006	**81,456,686**	**$376.9**	**43,931,484**	**$139.1**	**125,388,170**	**$516.0**

From January 1, 2007 to February 16, 2007, 600 Class A non-voting shares were issued with respect to the exercises of stock options and 5,000 Class B common shares were converted to Class A non-voting shares.

Earnings per share

Earnings per Class A non-voting and Class B common share is calculated by dividing the earnings attributable to Class A and Class B shares by the weighted average shares outstanding. Diluted earnings per share is calculated using the treasury stock method, which reflects the potential exercise of stock options on the weighted average Class A non-voting and Class B common shares outstanding. The average number of shares used to calculate earnings per share are as follows:

	Three Months Ended December 31		Year Ended December 31	
	2006	2005	**2006**	2005
	(Unaudited)			
Weighted average shares outstanding	**125,321,693**	126,928,689	**126,218,722**	126,901,614
Effect of dilutive stock options	**512,786**	685,048	**468,457**	551,357
Weighted average diluted shares outstanding	**125,834,479**	127,613,737	**126,687,179**	127,452,971

Share owner rights

The owners of the Class A non-voting shares and the Class B common shares are entitled to share equally, on a share for share basis, in all dividends declared by Canadian Utilities Limited on either of such classes of shares as well as the remaining property of Canadian Utilities Limited upon dissolution. The owners of the Class B common shares are entitled to vote and to exchange at any time each share held for one Class A non-voting share.

If a take-over bid is made for the Class B common shares which would result in the offeror owning more than 50% of the outstanding Class B common shares and which would constitute a change in control of Canadian Utilities Limited, owners of Class A non-voting shares are entitled, for the duration of the bid, to exchange their Class A non-voting shares for Class B common shares and to tender such Class B common shares pursuant to the terms of the take-over bid. Such right of exchange is conditional upon the completion of the take-over bid giving rise to the right of exchange, and if the take-over bid is not completed, then the right of exchange shall be deemed never to have existed. In addition, owners of the Class A non-voting shares are entitled to exchange their shares for Class B common shares of Canadian Utilities Limited if ATCO Ltd., the present controlling share owner of Canadian Utilities Limited, ceases to own or control, directly or indirectly, more than 10,000,000 of the issued and outstanding Class B common shares of Canadian Utilities Limited. In either case, each Class A non-voting share is exchangeable for one Class B common share, subject to changes in the exchange ratio for certain events such as a stock split or rights offering.

15. CLASS A AND CLASS B SHARES (CONTINUED)

Normal course issuer bid

On May 20, 2005, Canadian Utilities Limited commenced a normal course issuer bid for the purchase of up to 3% of the outstanding Class A non-voting shares. The bid expired on May 19, 2006. Over the life of the bid, 348,100 shares were purchased, of which 195,600 were purchased in 2005 and 152,500 were purchased in 2006. On May 23, 2006, Canadian Utilities Limited commenced a new normal course issuer bid for the purchase of up to 5% of the outstanding Class A shares. The bid will expire on May 22, 2007. From May 23, 2006, to February 16, 2007, 1,679,700 shares have been purchased, all of which were purchased in 2006.

Special dividend

The Corporation paid a Special Dividend of $0.25 per Class A non-voting and Class B common share on September 1, 2006.

16. STOCK BASED COMPENSATION PLANS

Stock option plan

Of the 6,400,000 Class A non-voting shares reserved for issuance in respect of options under Canadian Utilities Limited's stock option plan, 2,626,800 Class A non-voting shares are available for issuance at December 31, 2006. Options may be granted to directors, officers and key employees of Canadian Utilities Limited and its subsidiaries at an exercise price equal to the weighted average of the trading price of the shares on the Toronto Stock Exchange for the five trading days immediately preceding the date of grant. The vesting provisions and exercise period (which cannot exceed 10 years) are determined at the time of grant.

Changes in shares under option are summarized below:

	2006		2005	
	Class A Shares	**Weighted Average Exercise Price**	Class A Shares	Weighted Average Exercise Price
Options at beginning of year	**1,415,500**	**$21.59**	1,555,600	$19.45
Granted	**121,000**	**43.45**	204,000	30.50
Exercised	**(327,900)**	**16.62**	(338,000)	17.07
Cancelled	**(600)**	**24.52**	(6,100)	24.93
Options at end of year	**1,208,000**	**$25.12**	1,415,500	$21.59

Information about stock options outstanding at December 31, 2006 is summarized below:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Class A Shares	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Class A Shares	Weighted Average Exercise Price
$17.23 - $18.87	342,600	2.9	$17.84	342,600	$17.84
$20.65 - $28.65	540,400	3.3	23.60	494,400	23.39
$30.25 - $43.56	325,000	8.4	35.33	40,800	30.50
$17.23 - $43.56	1,208,000	4.6	$25.12	877,800	$21.56

In 2006, Canadian Utilities Limited granted 121,000 options to purchase Class A non-voting shares at a weighted average exercise price of $43.45 per share. The options have a term of ten years and vest over the first five years.

On January 2, 2007, Canadian Utilities Limited granted 161,500 options to purchase Class A non-voting shares at an exercise price of $47.84 per share. The options have a term of ten years and vest over the first five years.

16. STOCK BASED COMPENSATION PLANS (CONTINUED)

Changes in contributed surplus are summarized below:

	2006	2005
Contributed surplus at beginning of year	**$0.7**	$0.4
Stock option expense	**0.5**	0.3
Contributed surplus at end of year	**$1.2**	$0.7

The Corporation uses the Black-Scholes option pricing model, which estimated the weighted average fair value of the options granted during 2006 at $6.24 per option (2005 — $3.21 per option) using the following weighted average assumptions:

	2006	2005
Risk free interest rate	**4.0%**	4.0%
Expected holding period prior to exercise	**6.2 years**	6.3 years
Share price volatility	**11.9%**	11.7%
Estimated annual Class A share dividend	**2.5%**	3.5%

Share appreciation rights

Directors, officers and key employees of the Corporation may be granted share appreciation rights that are based on Class A non-voting shares of Canadian Utilities Limited or Class I Non-Voting shares of ATCO Ltd. The vesting provisions and exercise period (which cannot exceed 10 years) are determined at the time of grant. The base value of the share appreciation rights is equal to the weighted average of the trading price of the Class A non-voting shares and the Class I Non-Voting shares, respectively, on the Toronto Stock Exchange for the five trading days immediately preceding the date of grant. The holder is entitled on exercise to receive a cash payment equal to any increase in the market price of the Class A non-voting shares and Class I Non-Voting shares, respectively, over the base value of the share appreciation rights exercised.

Share appreciation rights expense amounted to $2.4 million (2005 — $9.0 million).

17. CHANGES IN NON-CASH WORKING CAPITAL

	2006	2005
Operating activities, changes related to:		
Accounts receivable	**$ (25.6)**	$ (6.7)
Inventories	**0.5**	85.3
Regulatory assets	**(10.6)**	(1.4)
Prepaid expenses	**(3.0)**	(1.7)
Accounts payable and accrued liabilities	**1.7**	29.3
Income taxes	**6.4**	(12.0)
Future income taxes	**(3.8)**	5.3
Regulatory liabilities	**(5.2)**	(7.9)
	$ (39.6)	$90.2
Investing activities, changes related to:		
Inventories	**$ (8.1)**	$ (1.5)
Prepaid expenses	**(0.3)**	0.1
Accounts payable and accrued liabilities	**(6.2)**	9.0
Income taxes	**(3.7)**	(11.0)
	$ (18.3)	$ (3.4)
Financing activities, changes related to:		
Accounts receivable	**$ (0.1)**	$ 3.1

18. JOINT VENTURES

The Corporation's interest in joint ventures is summarized below:

	2006	2005
Statement of earnings		
Revenues	**$ 533.0**	$ 528.6
Operating expenses	**328.1**	355.1
Depreciation and amortization	**40.4**	43.1
Interest	**41.2**	41.5
	123.3	88.9
Interest and other income	**8.9**	7.7
Earnings from joint ventures before income taxes	**$ 132.2**	$ 96.6
Balance sheet		
Current assets	**$ 266.9**	$ 247.4
Current liabilities	**(174.0)**	(159.6)
Property, plant and equipment	**933.2**	922.3
Deferred items – net	**(93.1)**	(101.3)
Non-recourse long term debt	**(465.2)**	(504.2)
Investment in joint ventures	**$ 467.8**	$ 404.6
Statement of cash flows		
Operating activities	**$ 180.8**	$ 175.4
Investing activities	**(19.1)**	(16.0)
Financing activities	**(131.0)**	(79.1)
Foreign currency translation	**14.1**	(9.5)
Increase in cash position	**$ 44.8**	$ 70.8

Current assets include cash of $160.9 million (2005 — $118.6 million) which is only available for use within the joint ventures (see Note 5).

19. RELATED PARTY TRANSACTIONS

In transactions with ATCO Ltd. and its wholly owned subsidiary corporations, the Corporation sold fuel in the amount of $2.2 million (2005 — $2.5 million), provided computer operations and systems development services totaling $2.4 million (2005 – $5.0 million), recovered administrative expenses totaling $2.4 million (2005 — $2.4 million) and incurred administrative expenses and corporate signature rights totaling $8.6 million (2005 — $7.1 million). Also, in transactions with an entity related through common control, the Corporation provided security services and recovered administrative expenses totaling $0.2 million (2005 – $0.2 million) and incurred advertising and promotion expenses totaling $1.7 million (2005 — $1.4 million).

At December 31, 2006, accounts receivable due from related parties amounted to $4.9 million (2005 – $1.8 million) and accounts payable due to related parties amounted to $3.2 million (2005 – $0.5 million).

These transactions are in the normal course of business and under normal commercial terms.

On October 1, 2006, the Corporation purchased the common shares of ATCO Európa Szerkezetgyártó és Kereskedelmi Kft. from an affiliate corporation for $0.5 million cash, partially offset by the forgiveness of $0.4 million of debt owed by the Corporation to the affiliate corporation. This purchase was recorded at carrying value, resulting in a charge to retained earnings of $0.3 million.

20. EMPLOYEE FUTURE BENEFITS

The Corporation maintains defined benefit and defined contribution pension plans for most of its employees and provides other post employment benefits, principally health, dental and life insurance, for retirees and their dependants. The defined benefit pension plans provide for pensions based on employees' length of service and final average earnings. As of 1997, new employees automatically participate in the defined contribution pension plan and employees participating in the defined benefit pension plans may transfer to the defined contribution pension plan at any time. Upon transfer, further accumulation of benefits under the defined benefit pension plans ceases.

Information about the Corporation's benefit plans, in aggregate, is as follows:

	2006		2005	
	Pension Benefit Plans	**Other Post Employment Benefit Plans**	Pension Benefit Plans	Other Post Employment Benefit Plans
Benefit plan assets, obligations and funded status				
Market value of plan assets:				
Beginning of year	**$1,561.1**	**$ -**	$1,402.1	$ -
Actual return on plan assets	**187.3**	**-**	197.0	-
Employee contributions	**3.7**	**-**	4.0	-
Benefit payments	**(39.8)**	**-**	(36.4)	-
Payments to defined contribution plans [1]	**(8.2)**	**-**	(5.6)	-
End of year	**$1,704.1**	**$ -**	$1,561.1	$ -
Accrued benefit obligations:				
Beginning of year	**$1,485.0**	**$ 80.3**	$1,232.7	$ 67.0
Current service cost	**38.0**	**3.0**	32.2	2.5
Interest cost	**80.8**	**4.2**	73.9	4.2
Employee contributions	**3.7**	**-**	4.0	-
Benefit payments from plan assets [2]	**(39.8)**	**-**	(36.4)	-
Benefit payments by employer	**(4.3)**	**(1.8)**	(4.7)	(1.9)
Experience losses (gains) [3]	**78.6**	**(2.2)**	183.3	8.5
End of year	**$1,642.0**	**$ 83.5**	$1,485.0	$ 80.3
Funded status:				
Excess (deficiency) of assets over obligations	**$ 62.1**	**$ (83.5)**	$ 76.1	$(80.3)
Amounts not yet recognized in financial statements:				
Unrecognized net cumulative experience losses on plan assets and accrued benefit obligations	**316.0**	**17.7**	369.5	21.9
Unrecognized net transitional liability (asset)	**(221.0)**	**20.7**	(253.4)	23.0
Accrued asset (liability) (Notes 10, 13)	**$ 157.1**	**$ (45.1)**	$ 192.2	$(35.4)
Regulatory asset (liability) [4] (Note 2)	**$ (118.7)**	**$ 27.6**	$ (139.4)	$ 22.0

(1) *Employer contributions for certain of the Corporation's defined contribution pension plans are paid from the assets of the defined benefit pension plans.*

(1) *Pension plan benefit payments are indexed to increases in the Canadian Consumer Price Index to a maximum increase of 3% per annum.*

(2) *Changes in assumptions regarding the average compensation rate increase for the year and age at retirement resulted in experience losses in 2006 of approximately $66 million for the pension benefit plans. A change in the liability discount rate assumption resulted in experience losses in 2005 of approximately $178 million for the pension benefit plans.*

(3) *The regulatory asset (liability) reflects an AEUB decision to record costs of employee future benefits in the regulated operations, excluding Alberta Power (2000), when paid rather than accrued.*

20. EMPLOYEE FUTURE BENEFITS (CONTINUED)

	2006		2005	
	Pension Benefit Plans	**Other Post Employment Benefit Plans**	Pension Benefit Plans	Other Post Employment Benefit Plans
Benefit plan cost				
Components of benefit plan cost:				
Current service cost	**$ 38.0**	**$ 3.0**	$ 32.2	$ 2.5
Interest cost	**80.8**	**4.2**	73.9	4.2
Actual return on plan assets	**(187.3)**	**-**	(197.0)	-
Experience losses (gains) on accrued benefit obligations	**78.6**	**(2.2)**	183.3	8.5
	10.1	**5.0**	92.4	15.2
Adjustments to recognize long term nature of employee future benefits:				
Unrecognized portion of actual return on plan assets	**107.6**	**-**	108.5	-
Unrecognized portion of experience gains (losses) on accrued benefit obligations	**(78.6)**	**2.2**	(183.3)	(8.5)
Amortization of net cumulative experience losses on plan assets and accrued benefit obligations	**24.5**	**2.0**	15.5	0.6
Amortization of net transitional liability (asset)	**(32.4)**	**2.3**	(32.8)	2.3
	21.1	**6.5**	(92.1)	(5.6)
Defined benefit plans cost	**31.2**	**11.5**	0.3	9.6
Defined contribution plans cost	**9.7**	**-**	7.0	-
Total cost	**40.9**	**11.5**	7.3	9.6
Less: Capitalized	**1.9**	**2.7**	1.4	2.3
Less: Unrecognized defined benefit plans cost (income) (1) (2)	**19.5**	**3.5**	(1.6)	3.3
Net cost recognized (2)	**$ 19.5**	**$ 5.3**	$ 7.5	$ 4.0

(1) *The unrecognized defined benefit plans cost (income) reflects an AEUB decision to record costs of employee future benefits in the regulated operations, excluding Alberta Power (2000), when paid rather than accrued.*

(2) *Net cost recognized for pension benefit plans in the three months ended December 31, 2006 includes the amortization of $5.1 million of the deferred pension assets recorded by the Corporation upon the adoption of the current accounting standard in 2000. On October 11, 2006, the AEUB approved recovery of these assets for a nine-year period commencing January 1, 2005 (Note 2).*

In the unaudited three months ended December 31, 2006, net cost of $7.8 million (2005 – $1.7 million) was recognized for pension benefit plans and net cost of $1.6 million (2005 – $0.6 million) was recognized for other post employment benefit plans.

Weighted average assumptions

	2006		2005	
	Pension Benefit Plans	**Other Post Employment Benefit Plans**	Pension Benefit Plans	Other Post Employment Benefit Plans
Assumptions regarding benefit plan cost:				
Expected long term rate of return on plan assets for the year	**6.1%**	**-**	6.9%	-
Liability discount rate for the year	**5.1%**	**5.1%**	5.9%	5.9%
Average compensation increase for the year	**3.5%**	**-**	3.25%	-
Assumptions regarding accrued benefit obligations:				
Liability discount rate at December 31	**5.1%**	**5.1%**	5.1%	5.1%
Long term inflation rate	**2.5%**	**(1)**	2.5%	(1)

(1) *The assumed annual health care cost trend rate increases used in measuring the accumulated post employment benefit obligation are as follows: for drug costs, 8.5% for 2006 grading down over 7 years to 4.5% (2005 – 9.3% for 2005 grading down over 8 years to 4.5%), and, for other medical and dental costs, 4.0% for 2006 and thereafter (2005 – 4.0% for 2005 and thereafter).*

20. EMPLOYEE FUTURE BENEFITS (CONTINUED)

The sensitivities of key assumptions used in measuring accrued benefit obligations and benefit plan cost for 2006 are outlined in the following table. The sensitivities of each key assumption have been calculated independently of changes in other key assumptions. Actual experience may result in changes in a number of assumptions simultaneously.

	2006 Pension Benefit Plans		2006 Other Post Employment Benefit Plans	
	Accrued Benefit Obligation	Benefit Plan Cost	Accrued Benefit Obligation	Benefit Plan Cost
Expected long term rate of return on plan assets				
1% increase (1)	-	$ (3.4)	-	-
1% decrease (1)	-	$ 3.4	-	-
Liability discount rate				
1% increase (1)	$(79.5)	$ (6.4)	$ (3.7)	$ (0.4)
1% decrease (1)	$101.7	$ 7.5	$ 4.7	$ 0.5
Future compensation rate				
1% increase (1)	$ 22.9	$ 2.9	-	-
1% decrease (1)	$(20.8)	$ (2.6)	-	-
Long term inflation rate				
1% increase (1) (2) (3)	$ 34.5	$ 3.9	$ 4.2	$ 0.7
1% decrease (1) (3)	$(60.4)	$ (6.9)	$ (3.4)	$ (0.5)

(1) *Sensitivities are net of the associated regulatory asset (liability) and unrecognized defined benefit plans cost, which reflect an AEUB decision to record costs of employee future benefits in the regulated operations, excluding Alberta Power (2000), when paid rather than accrued.*

(2) *The long term inflation rate for pension plans reflects the fact that pension plan benefit payments are indexed to increases in the Canadian Consumer Price Index to a maximum increase of 3.0% per annum.*

(3) *The long term inflation rate for other post employment benefit plans is the assumed annual health care cost trend rate described in the weighted average assumptions.*

Pension benefit plan assets

	2006		2005	
	Amount	**%**	Amount	%
Plan asset mix:				
Equity securities (1)	**$1,028.7**	**60.4**	$ 922.9	59.1
Fixed income securities (2)	**605.6**	**35.5**	567.7	36.4
Real estate (3)	**32.7**	**1.9**	31.1	2.0
Cash and other assets (4)	**37.1**	**2.2**	39.4	2.5
	$1,704.1	**100.0**	$1,561.1	100.0

(1) *Equity securities consist of investments in domestic and foreign preferred and common shares. At December 31, 2006, the market values of investments in United States' securities and international equities, denominated in a number of different currencies, are $236.7 million and $238.2 million, respectively (2005 – $144.0 million and $174.0 million, respectively).*

(2) *Fixed income securities consist of investments in federal and provincial government and corporate bonds and debentures.*

(3) *Real estate consists of investments in closed-end real estate funds.*

(4) *Cash and other assets consist of cash, short term notes and money market funds.*

At December 31, 2006, plan assets include long term debt of CU Inc. having a market value of $8.7 million (2005 – $6.0 million), Class A non-voting and Class B common shares of Canadian Utilities Limited having a market value of $19.1 million (2005 – $17.6 million) and Class I Non-Voting shares of ATCO Ltd. having a market value of $18.2 million (2005 – $14.8 million).

20. EMPLOYEE FUTURE BENEFITS (CONTINUED)

Funding

Employees are required to contribute a percentage of their salary to the defined benefit pension plans. The Corporation is required to provide the balance of the funding, based on triennial actuarial valuations, necessary to ensure that benefits will be fully provided for at retirement. Based on the most recent actuarial valuation for funding purposes as of December 31, 2004, the Corporation is continuing a contribution holiday that began on April 1, 1996. The next actuarial valuation for funding purposes is required as of December 31, 2007.

Included in the accrued benefit obligations are certain supplementary defined benefit pension plans that are paid by the Corporation out of general revenues. These supplementary plans had accrued benefit obligations of $84.2 million at December 31, 2006 (2005 – $77.4 million).

21. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

The Corporation is exposed to changes in interest rates, commodity prices and foreign currency exchange rates. The Power Generation segment is affected by the cost of natural gas and the price of electricity in the Province of Alberta and the United Kingdom and the Global Enterprises segment is affected by the cost of natural gas and the price of natural gas liquids. In conducting its business, the Corporation uses various instruments, including forward contracts, swaps and options, to manage the risks arising from fluctuations in exchange rates, interest rates and commodity prices. All such instruments are used only to manage risk and not for trading purposes.

Interest rate risk

Long term debt and non-recourse long term debt have variable interest rates that have been hedged through the following interest rate swap agreements:

Swap Fixed Interest Rate [1]	Variable Debt Interest Rate	Completion Date	Principal/Face Value 2006	2005
5.287%	90 day BA	December 2007	**$ 40.8**	$ 44.4
5.212%	90 day BA	September 2008	**54.2**	59.2
7.54%	90 day BA	November 2008	**2.6**	3.8
7.317%	90 day BA	December 2008	**3.6**	5.4
5.8367%	90 day BA	June 2009	**8.9**	9.4
6.346%	90 day BA	June 2011	**2.7**	3.3
7.50%	6 month LIBOR	December 2011	**83.8**	87.5
7.286%	90 day BA	September 2012	**24.0**	28.2
7.3325%	Bank Bill Rate in Australia	December 2013	**31.8**	34.4
6.575%	90 day BA	March 2019	**36.1**	37.8
			$288.5	$313.4

BA – Bankers' Acceptance
LIBOR – London Interbank Offered Rate

(1) The above swap fixed interest rates include any long term debt margin fees; the margin fees are subject to escalation (Note 12).

Foreign exchange rate risk

The Corporation has exposure to changes in the carrying values of its foreign operations, including assets and liabilities, as a result of changes in exchange rates.

The Corporation has entered into foreign exchange forward contracts in order to fix the exchange rate on certain planned equipment expenditures denominated in U.S. dollars and Euros. At December 31, 2006, the contracts consist of purchases of $0.2 million U.S. (2005 – $2.6 million U.S.) and sales of 3.0 million Euros (2005 – 2.0 million Euros).

21. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS (CONTINUED)

Energy commodity price risk

In March 2004, the AEUB issued a decision respecting the operation of ATCO Gas' Carbon storage facility for the 2004/2005 storage year, which ended on March 31, 2005. The decision directed ATCO Gas to continue to reserve 16.7 petajoules of storage capacity for the benefit of utility customers. As a result of an AEUB approved storage plan, ATCO Gas entered into certain energy contracts for the forward purchase and sale of natural gas for storage purposes. All associated costs and benefits of these contracts were passed to customers through regulated rates and, accordingly, ATCO Gas did not bear any risk for price fluctuations provided that the contracts were in accordance with the storage plan. Since April 1, 2005, ATCO Gas has leased the entire storage capacity of the Carbon facility to ATCO Midstream.

Fair values

The fair values of derivatives have been estimated using year-end market rates. These fair values approximate the amount that the Corporation would either pay or receive to settle the contract at December 31.

	2006			2005		
	Notional Principal	**Fair Value (Payable) Receivable**	**Maturity**	Notional Principal	Fair Value (Payable) Receivable	Maturity
Interest rate swaps	**$288.5**	**$ (7.3)**	**2007-2019**	$313.4	$(10.5)	2007-2019
Foreign exchange forward contracts	**$ 4.6**	**$ 0.3**	**2007**	$ 5.9	$ (0.1)	2006

Credit risk

Derivative credit risk arises from the possibility that a counterparty to a contract fails to perform according to the terms and conditions of that contract. Derivative credit risk is minimized by dealing with large, credit-worthy counterparties in accordance with established credit approval policies. Accounts receivable credit risk is reduced by a large and diversified customer base, requirement of letters of credit, and, for regulated operations other than Alberta Power (2000), the ability to recover an estimate for doubtful accounts through approved customer rates.

22. COMMITMENTS AND CONTINGENCIES

Commitments

The Corporation has contractual obligations in the normal course of business; future minimum payments are as follows:

	2007	2008	2009	2010	2011	Total of All Subsequent Years
Operating leases [1]	$ 18.5	$ 15.8	$ 8.8	$ 7.7	$ 6.0	$ 4.8
Purchase obligations:						
Coal purchase contracts [2]	47.7	48.9	50.3	51.8	53.4	355.6
Natural gas purchase contracts [3]	52.9	52.9	52.9	52.9	22.1	18.9
Operating and maintenance agreements [4]	21.2	24.1	21.2	20.6	17.8	93.3
	$140.3	$141.7	$133.2	$133.0	$ 99.3	$472.6

(1) *Operating leases are comprised primarily of long term leases for office premises and equipment.*

(2) *Alberta Power (2000) has fixed price long term contracts to purchase coal for its coal-fired generating plants.*

(3) *Natural gas purchase contracts consist primarily of ATCO Power contracts to purchase natural gas for certain of its natural gas-fired generating plants.*

(4) *ATCO Power has long term service agreements with suppliers to provide operating and maintenance services at certain of its generating plants.*

22. COMMITMENTS AND CONTINGENCIES (CONTINUED)

Contingencies

Measurement inaccuracies occur from time to time with respect to ATCO Electric's, ATCO Gas' and ATCO Pipelines' metering facilities. Measurement adjustments are settled between the parties based on the requirements of the Electricity and Gas Inspections Act (Canada) and applicable regulations issued pursuant thereto. There is a risk of disallowance of the recovery of a measurement adjustment if controls and timely follow-up are found to be inadequate by the AEUB.

On December 23, 2005, the Government of Canada filed a claim in the amount of $70 million which alleges that the Corporation is liable for the destruction of property owned by the Governments of Canada and the United States. The Corporation believes that the claim is defensible and, in any event, has sufficient insurance coverage in place to cover any material amounts that might become payable as a result of the claim. Accordingly, the claim is not expected to have any material impact on the financial position of the Corporation.

The Corporation is party to a number of other disputes and lawsuits in the normal course of business. The Corporation believes that the ultimate liability arising from these matters will have no material impact on the consolidated financial statements.

As a result of decisions of the Supreme Court of Canada in Garland vs. Consumers' Gas Co., the imposition of late payment penalties on utility bills has been called into question. The Corporation is unable to determine at this time the impact, if any, that these decisions will have on the Corporation.

23. SEGMENTED INFORMATION

Description of segments

The Corporation operates in the following business segments:

The **Utilities** Business Group includes the regulated distribution of natural gas by ATCO Gas, the regulated distribution and transmission of electric energy by ATCO Electric and its subsidiaries, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical, the regulated transportation of natural gas by ATCO Pipelines, the regulated transmission and distribution of water by CU Water, and the provision of non-regulated complementary projects by ATCO Utility Services.

The **Power Generation** Business Group includes the non-regulated supply of electricity and cogeneration steam by ATCO Power, the regulated supply of electricity by Alberta Power (2000), and the sale of fly ash and other combustion byproducts produced in coal fired electrical generating plants by ASHCOR Technologies.

The **Global Enterprises** Business Group includes the non-regulated gathering, processing, storage, purchase and sale of natural gas by ATCO Midstream, the provision of project management and technical services for customers in the industrial, defence and transportation sectors by ATCO Frontec, the development, operation and support of information systems and technologies by ATCO I-Tek, the provision of billing services, payment processing, credit, collection and call centre services by ATCO I-Tek's subsidiary, ATCO I-Tek Business Services, and the sale of travel services to both business and consumer sectors by ATCO Travel. The Corporation sold its 50% interest in Genics, a manufacturer of wood preservation products, effective August 1, 2006.

The Corporate and Other segment includes commercial real estate owned by the Corporation in Alberta.

23. SEGMENTED INFORMATION (CONTINUED)

Segmented results – Three months ended December 31

2006 / 2005	Utilities	Power Generation (2)	Global Enterprises (2)	Corporate & Other	Intersegment Eliminations	Consolidated
(Unaudited)						
Revenues – external	**$308.4**	**$226.7**	**$135.6**	**$ 0.4**	**$ -**	**$671.1**
	$ 299.1	$ 211.0	$ 169.9	$ 0.3	$ -	$ 680.3
Revenues – intersegment (1)	**6.3**	**-**	**38.3**	**2.9**	**(47.5)**	**-**
	6.4	-	30.0	2.9	(39.3)	-
Revenues	**$314.7**	**$226.7**	**$173.9**	**$ 3.3**	**$(47.5)**	**$671.1**
	$ 305.5	$ 211.0	$ 199.9	$ 3.2	$ (39.3)	$ 680.3
Earnings attributable to Class A and Class B shares	**$ 43.7**	**$ 36.9**	**$ 27.3**	**$ (6.5)**	**$ (1.4)**	**$100.0**
	$ 32.5	$ 36.7	$ 27.6	$ (7.5)	$ (0.2)	$ 89.1

Segmented results – Year ended December 31

2006 / 2005	Utilities	Power Generation (2)	Global Enterprises (2)	Corporate & Other	Intersegment Eliminations	Consolidated
Revenues – external	**$1,086.2**	**$ 799.5**	**$543.3**	**$ 1.4**	**$ -**	**$2,430.4**
	$ 1,173.5	$ 770.7	$ 570.4	$ 1.2	$ -	$ 2,515.8
Revenues – intersegment (1)	**24.6**	**-**	**123.9**	**11.3**	**(159.8)**	**-**
	22.4	-	108.6	11.2	(142.2)	-
Revenues	**1,110.8**	**799.5**	**667.2**	**12.7**	**(159.8)**	**2,430.4**
	1,195.9	770.7	679.0	12.4	(142.2)	2,515.8
Operating expenses	**601.4**	**431.3**	**490.5**	**18.7**	**(151.2)**	**1,390.7**
	716.9	420.4	533.1	24.4	(140.9)	1,553.9
Depreciation & amortization	**220.2**	**95.4**	**31.5**	**1.4**	**-**	**348.5**
	189.3	95.8	24.8	1.6	-	311.5
Interest expense	**132.5**	**92.2**	**2.2**	**162.4**	**(166.4)**	**222.9**
	124.9	84.8	2.4	154.6	(156.7)	210.0
Interest and other income	**(20.3)**	**(11.9)**	**(4.1)**	**(188.6)**	**166.4**	**(58.5)**
	(11.8)	(9.3)	(2.0)	(170.2)	156.7	(36.6)
Earnings before income taxes	**177.0**	**192.5**	**147.1**	**18.8**	**(8.6)**	**526.8**
	176.6	179.0	120.7	2.0	(1.3)	477.0
Income taxes	**45.4**	**69.7**	**46.1**	**8.7**	**(2.8)**	**167.1**
	60.2	70.2	41.9	3.7	(0.4)	175.6
	131.6	**122.8**	**101.0**	**10.1**	**(5.8)**	**359.7**
	116.4	108.8	78.8	(1.7)	(0.9)	301.4
Dividends on equity preferred shares	**10.4**	**3.6**	**-**	**21.8**	**-**	**35.8**
	10.4	3.6	-	21.8	-	35.8
Earnings attributable to Class A and Class B shares	**$ 121.2**	**$ 119.2**	**$101.0**	**$ (11.7)**	**$ (5.8)**	**$ 323.9**
	$ 106.0	$ 105.2	$ 78.8	$ (23.5)	$ (0.9)	$ 265.6
Total Assets	**$3,799.0**	**$2,240.0**	**$278.1**	**$576.2**	**$100.2**	**$6,993.5**
	$ 3,526.8	$ 2,219.6	$ 303.7	$ 614.9	$ 152.8	$ 6,817.8
Purchase of property, plant and equipment	**$ 505.0**	**$ 48.1**	**$ 14.2**	**$ 0.4**	**$ -**	**$ 567.7**
	$ 472.9	$ 41.2	$ 11.9	$ 0.7	$ -	$ 526.7

(1) *Intersegment revenues are recognized on the basis of prevailing market or regulated prices.*

(2) *In 2006, ASHCOR Technologies was transferred from the Global Enterprises Business Group to the Power Generation Business Group. 2005 segmented figures have been reclassified to conform to the current basis of segmentation.*

23. SEGMENTED INFORMATION (CONTINUED)

Geographic segments

	Domestic		Foreign		Consolidated	
	2006	2005	**2006**	2005	**2006**	2005
Revenues	**$2,130.6**	$2,253.6	**$299.8**	$262.2	**$2,430.4**	$2,515.8
Property, plant and equipment	**$5,099.5**	$4,905.9	**$326.6**	$302.8	**$5,426.1**	$5,208.7

CANADIAN UTILITIES LIMITED

Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD&A")

For The Year Ended December 31, 2006

The following discussion and analysis of financial condition and results of operations of Canadian Utilities Limited (the "Corporation") should be read in conjunction with the Corporation's unaudited consolidated interim financial statements for the three months ended December 31, 2006, and the audited consolidated financial statements for the year ended December 31, 2006. Additional information relating to the Corporation, including the Corporation's Annual Information Form, is available on SEDAR at www.sedar.com.

All quarterly information in this document is unaudited and is shaded to differentiate it from the annual information.

The equity securities of the Corporation consist of Class A non-voting shares ("Class A shares") and Class B common shares ("Class B shares").

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FORWARD-LOOKING INFORMATION

Certain statements contained in this MD&A constitute forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "anticipate", "plan", "estimate", "expect", "may", "will", "intend", "should", and similar expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Corporation believes that the expectations reflected in the forward-looking statements are reasonable, but no assurance can be given that these expectations will prove to be correct and such forward-looking statements should not be unduly relied upon.

In particular, this MD&A contains forward-looking statements pertaining to contractual obligations, planned capital expenditures, the impact of changes in government regulation and non-regulated generating capacity subject to long term contracts. The Corporation's actual results could differ materially from those anticipated in these forward-looking statements as a result of regulatory decisions, competitive factors in the industries in which the Corporation operates, prevailing economic conditions, and other factors, many of which are beyond the control of the Corporation.

NON-GAAP FINANCIAL MEASURES

In this MD&A, reference is made to funds generated by operations, which is a measure that does not have a standardized meaning under Canadian Generally Accepted Accounting Principles ("GAAP"). Funds generated by operations is calculated on the Corporation's consolidated statement of cash flows from operating activities before changes in non-cash working capital. In the Corporation's opinion, funds generated by operations is a significant performance indicator of the Corporation's ability to generate cash flow to fund its capital expenditures.

CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

As of December 31, 2006, the Corporation's management evaluated the effectiveness of the design and operation of its disclosure controls and procedures ("Disclosure Controls") as defined under rules adopted by the Canadian Securities Administrators. This evaluation was performed under the supervision of, and with the participation of, the Chief Executive Officer ("CEO") and the Chief Financial Officer ("CFO").

Disclosure Controls are procedures designed to ensure that information required to be disclosed in documents filed with securities regulatory authorities is recorded, processed, summarized and reported on a timely basis, and is accumulated and communicated to the Corporation's management, including the CEO and the CFO, as appropriate, to allow timely decisions regarding required disclosure.

The Corporation's management, including the CEO and the CFO, does not expect that the Corporation's Disclosure Controls will prevent or detect all error and all fraud. The inherent limitations in all control systems are such that they can provide only reasonable, not absolute, assurance that all control issues and instances of fraud or error, if any, within the Corporation have been detected.

Based on the evaluation of Disclosure Controls, the CEO and the CFO have concluded that, subject to the inherent limitations noted above, the Corporation's Disclosure Controls are effective in providing reasonable assurance that material information relating to the Corporation and its consolidated subsidiaries is made known to the Corporation's management.

Internal Control Over Financial Reporting

As of December 31, 2006, management of the Corporation is responsible for evaluating the design of internal control over financial reporting ("Internal Control Over Financial Reporting"), as defined under rules adopted by the Canadian Securities Administrators. This evaluation was performed under the supervision of, and with the participation of, the CEO and the CFO. The Corporation's internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Internal control over financial reporting, no matter how well designed, has inherent limitations. Therefore, internal control over financial reporting can provide only reasonable assurance with respect to financial statement preparation and may not prevent or detect all misstatements.

There were no changes in the Corporation's internal controls over financial reporting that have occurred during the three months ended December 31, 2006, that have materially affected, or are reasonably likely to materially affect, the Corporation's internal control over financial reporting.

BUSINESS OF THE CORPORATION

The Corporation's financial statements are consolidated from three Business Groups: Utilities, Power Generation and Global Enterprises. For the purposes of financial disclosure, corporate transactions are accounted for as Corporate and Other (refer to Note 23 to the consolidated financial statements for the year ended December 31, 2006). Transactions between Business Groups are eliminated in all reporting of the Corporation's consolidated financial information.

In 2006, ASHCOR Technologies was transferred from the Global Enterprises Business Group to the Power Generation Business Group. 2005 segmented figures have been reclassified to conform to the current basis of segmentation. On August 1, 2006, the Corporation sold its 50% equity interest in Genics Inc., which was part of the Global Enterprises Business Group.

STRATEGIC ALTERNATIVES FOR MIDSTREAM ASSETS

On November 24, 2006, the Corporation announced that its Board of Directors had completed its review of the strategic alternatives available for its gas gathering and processing and natural gas liquids midstream business and reached a decision to retain the business under the Corporation's current structure. The strategic review, commenced in May 2006, was conducted by the Board of Directors in conjunction with the Corporation's management and legal and financial advisors. The review involved the evaluation of a number of alternatives, including reorganization into a business trust or newly-created company or a sale to a third party.

TXU EUROPE SETTLEMENT

On November 19, 2002, an administration order was issued by an English Court against TXU Europe Energy Trading Limited ("TXU Europe") for breach of its contract to purchase 27.5% of the power produced by the 1,000 megawatt Barking generating plant, in which the Corporation owns a 25.5% equity interest. In 2005, the Corporation received \$83.1 million as its share of the partial settlement of the claim for damages related to TXU Europe's breach of this contract. An additional payment of \$16.6 million was received on January 19, 2006 and a final installment of approximately \$1.6 million was received on July 20, 2006. The settlement is expected to generate earnings after income taxes of approximately \$69 million, based on foreign currency exchange rates in effect on March 30, 2005, which will be recognized over the remaining term of the TXU Europe contract from October 1, 2004, to September 30, 2010, at approximately \$11 million per year. These earnings will be dependent upon the foreign currency exchange rates in effect at the time the earnings are recognized. For a description of the settlement, refer to Note 5 to the consolidated financial statements for the year ended December 31, 2006.

H.R. MILNER INCOME TAX REASSESSMENT

In 2006, the Canada Revenue Agency ("CRA") issued a reassessment for Alberta Power (2000)'s 2001 taxation year. The CRA's reassessment treats the proceeds received from the sale of the H.R. Milner generating plant to the Alberta Balancing Pool as income rather than as a sale of an asset. The Corporation has made submissions to the CRA opposing the CRA's position. The impact of the reassessment is a $12.4 million increase in interest and income tax expense, a $12.4 million decrease in earnings and a $28.8 million payment associated with the tax and interest assessed. It is expected that $16.4 million of this cash payment will be recovered by reducing income taxes payable through higher capital cost allowance claims. Due to the uncertainty as to whether the reassessment will ultimately be resolved in the Corporation's favour, the Corporation reduced earnings by $12.4 million in 2006.

RECENT CHANGES IN INCOME TAXES AND RATES

Federal and provincial governments have recently announced a number of changes to income taxes and rates. As these changes are considered to have been substantively enacted, the Corporation made an adjustment to income taxes amounting to $11.8 million in the second quarter of 2006, most of which relates to future income taxes. The adjustment increased 2006 earnings by $11.8 million, of which $1.9 million relates to the Utilities Business Group, $7.2 million to the Power Generation Business Group, $2.3 million to the Global Enterprises Business Group and $0.4 million to Corporate and Other.

SELECTED ANNUAL AND QUARTERLY INFORMATION

	For the Three Months Ended				Year Ended
($ Millions except per share data)	Mar. 31	Jun. 30	Sep. 30	Dec. 31	Dec. 31
	(unaudited)				
2006 [1] [2]					
Revenues [3] [4]	642.0	563.4	553.9	671.1	2,430.4
Earnings attributable to Class A and Class B shares [4]	86.9	70.2	66.8	100.0	323.9
Earnings per Class A and Class B share	0.68	0.56	0.53	0.80	2.57
Diluted earnings per Class A and Class B share	0.68	0.55	0.53	0.80	2.56
2005 [1] [2]					
Revenues [3] [4]	745.2	552.9	537.4	680.3	2,515.8
Earnings attributable to Class A and Class B shares [4]	80.0	50.0	46.5	89.1	265.6
Earnings per Class A and Class B share	0.63	0.39	0.37	0.70	2.09
Diluted earnings per Class A and Class B share	0.63	0.39	0.37	0.69	2.08
2004 [1] [2]					
Revenues [3] [4]					3,011.4
Earnings attributable to Class A and Class B shares [5]					309.0
Earnings per Class A and Class B share [5]					2.44
Diluted earnings per Class A and Class B share [5]					2.43

Notes:

(1) *There were no discontinued operations or extraordinary items during these periods.*

(2) *Due to the seasonal nature of the Corporation's operations, changes in electricity prices in Alberta and the timing of rate decisions, revenues and earnings for any quarter are not necessarily indicative of operations on an annual basis.*

(3) *Reduced recoveries of natural gas costs in revenues in 2006 and 2005 as ATCO Gas ceased selling natural gas from its natural gas storage facilities on March 31, 2005, in accordance with Alberta Energy and Utilities Board directives.*

(4) *Prior to the Transfer of the Retail Energy Supply Businesses on May 4, 2004, the cost of natural gas and electricity purchased for ATCO Gas' and ATCO Electric's customers was included in revenues. As ATCO Gas and ATCO Electric no longer purchase natural gas and electricity for their customers, revenues since May 4, 2004, have decreased accordingly.*

(5) *Includes earnings of $55.1 million, earnings per share of $0.44 and diluted earnings per share of $0.43 on the Transfer of the Retail Energy Supply Businesses for the year ended December 31, 2004.*

(6) *The above data has been extracted from the financial statements which have been prepared in accordance with Canadian generally accepted accounting principles and the reporting currency is the Canadian dollar.*

SELECTED ANNUAL AND QUARTERLY INFORMATION

	Year Ended December 31		
	2006	2005	2004
	($ Millions except per share data)		
Cash dividends declared per share:			
Series Second Preferred Shares:			
Series O [(2)]	1.26	1.26	1.26
Series Q	1.48	1.48	1.48
Series R	1.33	1.33	1.33
Series S	1.65	1.65	1.65
Series T [(2)]	1.26	1.26	1.26
Series U [(2)]	1.26	1.26	1.26
Series V	1.31	1.31	1.31
Series W	1.45	1.45	1.45
Series X	1.50	1.50	1.50
Class A and Class B shares	1.40	1.10	1.06
Total assets	6,993.5	6,817.8	6,617.5
Long term debt	2,411.5	2,231.0	2,171.0
Non-recourse long term debt	626.7	673.8	760.9
Equity preferred shares	636.5	636.5	636.5
Class A and Class B share owners' equity	2,324.7	2,223.5	2,117.7

Notes:

(1) The above data has been extracted from the financial statements which have been prepared in accordance with Canadian generally accepted accounting principles and the reporting currency is the Canadian dollar.

(2) The dividend was reset to $1.09 (4.35%) for the period between December 2, 2006, and December 2, 2011.

RESULTS OF OPERATIONS

The principal factors that caused variations in **revenues** over the eight most recently completed quarters were:

- reduced recoveries of natural gas costs in revenues in 2006 as ATCO Gas ceased selling natural gas from its natural gas storage facilities on March 31, 2005, in accordance with Alberta Energy and Utilities Board ("AEUB") directives;
- fluctuations in temperatures (refer to the Utilities section);
- timing of rate decisions (refer to the Utilities and Regulatory Matters sections);
- availability of generating plants in ATCO Power and Alberta Power (2000) (refer to the Power Generation section);
- fluctuations in electricity and natural gas prices (refer to the Power Generation section); and
- changes in market conditions in natural gas liquids and storage operations (refer to the Global Enterprises section).

The principal factors that caused variations in **earnings** over the eight most recently completed quarters were:

- fluctuations in temperatures (refer to the Utilities section);
- timing of rate decisions (refer to the Utilities and Regulatory Matters sections);
- fluctuations in electricity prices and related spark spreads in Alberta and the United Kingdom ("U.K.") (refer to the Power Generation section);
- the TXU Europe Settlement (refer to TXU Europe Settlement section);
- H.R. Milner income tax reassessment (refer to H.R. Milner Income Tax Reassessment section);
- availability of generating plants in ATCO Power and Alberta Power (2000) (refer to the Power Generation section);
- changes in market conditions in natural gas liquids and storage operations (refer to the Global Enterprises section);
- recent changes in income taxes and rates (refer to Recent Changes in Income Taxes and Rates section); and

- changes in share appreciation rights expense due to changes in Canadian Utilities Limited Class A non-voting share and ATCO Ltd. Class I Non-Voting Share prices (refer to Corporate and Other section).

Consolidated Operations

Revenues for the three months ended December 31, 2006, **decreased** by $9.2 million to $671.1 million, primarily due to:

- lower recovery of natural gas costs in revenues due to customers supplying shrinkage gas in ethane extraction operations in ATCO Midstream;
- lower volumes of natural gas purchased and resold for natural gas liquids extraction in ATCO Midstream; and
- lower franchise fees collected by ATCO Gas on behalf of cities and municipalities.

This decrease was partially offset by:

- higher availability (due to a planned outage in 2005), improved merchant performance, and higher natural gas fuel purchases recovered on a "no-margin" basis in ATCO Power's U.K. operations; and
- colder temperatures in ATCO Gas.

Revenues for the year ended December 31, 2006, **decreased** by $85.4 million to $2,430.4 million, primarily due to:

- reduced recoveries of natural gas costs in revenues in 2006 as ATCO Gas ceased selling natural gas from its natural gas storage facilities on March 31, 2005, in accordance with Alberta Energy and Utilities Board ("AEUB") directives;
- lower recovery of natural gas costs in revenues due to customers supplying shrinkage gas in ethane extraction operations in ATCO Midstream;
- lower volumes of natural gas purchased and resold for natural gas liquids extraction in ATCO Midstream;
- lower business activity in ATCO Frontec; and
- impact of lower U.K. and Australia exchange rates on conversion of revenues to Canadian dollars in ATCO Power.

This decrease was partially offset by:

- improved merchant performance, higher natural gas fuel purchases recovered on a "no-margin" basis, and higher availability (due to a planned outage in 2005) in ATCO Power's U.K. operations;
- higher storage revenues due to higher capacity leased, and the timing and demand of storage capacity sold, by ATCO Midstream; and
- higher customer rates for ATCO Electric (refer to Regulatory Matters – ATCO Electric section). The impact of the ATCO Electric GTA Decision on 2006 was positive as ATCO Electric had lower customer rates during 2005.

Earnings attributable to Class A and Class B shares for the three months ended December 31, 2006, **increased** by $10.9 million ($0.10 per share) to $100.0 million ($0.80 per share), primarily due to:

- higher earnings in ATCO Power's Alberta generating plants due to higher spark spreads realized on sales of electricity in the Alberta market; and
- colder temperatures in ATCO Gas.

This increase was partially offset by:

- higher maintenance expenses due to a planned outage in 2006 at Alberta Power (2000)'s Battle River generating plant; and
- a settlement with a supplier was recorded in the fourth quarter of 2005 for damages due to equipment defects in ATCO Power's U.K. operations.

Earnings attributable to Class A and Class B shares for the year ended December 31, 2006, **increased** by $58.3 million ($0.48 per share) to $323.9 million ($2.57 per share), primarily due to:

- higher earnings in ATCO Power's Alberta generating plants due to higher spark spreads realized on sales of electricity in the Alberta market;
- higher margins received for natural gas liquids, higher storage earnings due to higher capacity leased, and the timing and demand of storage capacity sold by ATCO Midstream; and
- $11.8 million adjustment in the second quarter of 2006 to reflect recent tax changes (refer to Recent Changes in Income Taxes and Rates section).

This increase was partially offset by:

- H.R. Milner Income Tax Reassessment (refer to H.R. Milner Income Tax Reassessment section); and
- a 2005 AEUB decision adjusting the 2001 and 2002 revenue requirements for changes in future income taxes recorded in ATCO Electric (refer to Regulatory Matters – ATCO Electric section).

Return on common equity was 14.3% in 2006.

Operating expenses (consisting of natural gas supply, purchased power, operation and maintenance, selling and administrative and franchise fee costs) for the three months ended December 31, 2006, **decreased** by $15.5 million to $383.5 million, primarily due to:

- lower costs for natural gas liquids extraction in ATCO Midstream.

This decrease was partially offset by:

- higher maintenance expenses due to a planned outage in 2006 at Alberta Power (2000)'s Battle River generating plant.

Operating expenses for the year ended December 31, 2006, **decreased** by $163.2 million to $1,390.7 million, primarily due to:

- reduced natural gas supply costs in 2006 as ATCO Gas ceased selling natural gas from its natural gas storage facilities on March 31, 2005, in accordance with AEUB directives; and
- lower volumes of natural gas purchased for natural gas liquids extraction in ATCO Midstream.

Depreciation and amortization expenses for the three months ended December 31, 2006, **increased** by $11.1 million to $95.6 million, primarily due to:

- capital additions in 2006 and 2005.

Depreciation and amortization expenses for the year ended December 31, 2006, **increased** by $37.0 million to $348.5 million, primarily due to:

- capital additions in 2006 and 2005.

Interest expense for the three months ended December 31, 2006, **increased** by $3.2 million to $54.6 million, primarily due to:

- interest on new financings issued in 2006 and 2005 to fund capital expenditures in Utilities operations.

This increase was partially offset by:

- repayment of non-recourse financings in 2006 and 2005.

Interest expense for the year ended December 31, 2006, **increased** by $12.9 million to $222.9 million, primarily due to:

- H.R. Milner Income Tax Reassessment (refer to H.R. Milner Income Tax Reassessment section); and
- interest on new financings issued in 2006 and 2005 to fund capital expenditures in Utilities operations.

This increase was partially offset by:

- repayment of non-recourse financings in 2006 and 2005.

Interest and other income for the three months ended December 31, 2006, **increased** by $8.3 million to $18.9 million, primarily due to:

- higher short term interest rates on cash balances.

Interest and other income for the year ended December 31, 2006, **increased** by $21.9 million to $58.5 million, primarily due to:

- Calgary Stores Block Decision (refer to Regulatory Matters – ATCO Gas section); and
- higher short term interest rates on larger cash balances.

Income taxes for the three months ended December 31, 2006, **decreased** by $10.6 million to $47.4 million, primarily due to:

- lower tax rates.

Income taxes for the year ended December 31, 2006, **decreased** by $8.5 million to $167.1 million, primarily due to:

- adjustment to reflect recent tax changes (refer to Recent Changes in Income Taxes and Rates section).

This decrease was partially offset by:

- higher earnings; and
- H.R. Milner Income Tax Reassessment (refer to H.R. Milner Income Tax Reassessment section).

Segmented Information

Segmented revenues for the three months and the year ended December 31, 2006, were as follows:

($ Millions)	For the Three Months Ended December 31		For the Year Ended December 31	
	2006	2005	**2006**	2005
	(unaudited)			
Utilities [1]	**314.7**	305.5	**1,110.8**	1,195.9
Power Generation [2]	**226.7**	211.0	**799.5**	770.7
Global Enterprises [2]	**173.9**	199.9	**667.2**	679.0
Corporate and Other	**3.3**	3.2	**12.7**	12.4
Intersegment eliminations	**(47.5)**	(39.3)	**(159.8)**	(142.2)
Total	**671.1**	680.3	**2,430.4**	2,515.8

Notes:

[1] *Reduced recoveries of natural gas costs in revenues in 2006 as ATCO Gas ceased selling natural gas from its natural gas storage facilities on March 31, 2005, in accordance with AEUB directives.*

[2] *In 2006, ASHCOR Technologies was transferred from the Global Enterprises Business Group to the Power Generation Business Group. 2005 segmented figures have been reclassified to conform to the current basis of segmentation.*

Segmented earnings attributable to Class A and Class B shares for the three months and the year ended December 31, 2006, were as follows:

($ Millions)	For the Three Months Ended December 31		For the Year Ended December 31	
	2006	2005	**2006**	2005
	(unaudited)			
Utilities	**43.7**	32.5	**121.2**	106.0
Power Generation [1]	**36.9**	36.7	**119.2**	105.2
Global Enterprises [1]	**27.3**	27.6	**101.0**	78.8
Corporate and Other	**(6.5)**	(7.5)	**(11.7)**	(23.5)
Intersegment eliminations	**(1.4)**	(0.2)	**(5.8)**	(0.9)
Total	**100.0**	89.1	**323.9**	265.6

Note:

[1] *In 2006, ASHCOR Technologies was transferred from the Global Enterprises Business Group to the Power Generation Business Group. 2005 segmented figures have been reclassified to conform to the current basis of segmentation.*

Utilities

Revenues from the Utilities Business Group for the three months ended December 31, 2006, **increased** by $9.2 million to $314.7 million, primarily due to:

- colder temperatures in ATCO Gas;
- higher customer rates for ATCO Electric (refer to Regulatory Matters – ATCO Electric section). The impact of the ATCO Electric GTA Decision on the fourth quarter of 2006 was positive as ATCO Electric had lower customer rates during the fourth quarter of 2005; and
- customer growth in ATCO Gas.

This increase was partially offset by:

- lower franchise fees collected by ATCO Gas on behalf of cities and municipalities.

Temperatures in ATCO Gas for the three months ended December 31, 2006, were 5.2% colder than normal, compared to 14.1% warmer than normal for the corresponding period in 2005.

Revenues for the year ended December 31, 2006, **decreased** by $85.1 million to $1,110.8 million, primarily due to:

- reduced recoveries of natural gas costs in revenues in 2006 as ATCO Gas ceased selling natural gas from its natural gas storage facilities on March 31, 2005, in accordance with AEUB directives; and
- lower income taxes recovered from ATCO Electric's customers on a flow through basis, reflecting lower income tax rates in 2006.

This decrease was partially offset by:

- higher customer rates for ATCO Electric (refer to Regulatory Matters – ATCO Electric section). The impact of the ATCO Electric GTA Decision on 2006 was positive as ATCO Electric had lower customer rates during 2005; and
- customer growth in ATCO Gas.

Temperatures in ATCO Gas in 2006 were 5.5% warmer than normal, compared to 7.8% warmer than normal in 2005.

Earnings for the three months ended December 31, 2006, **increased** by $11.2 million to $43.7 million, primarily due to:

- colder temperatures in ATCO Gas.

This increase was partially offset by:

- lower sales per customer in ATCO Gas.

Earnings for the year ended December 31, 2006, **increased** by $15.2 million to $121.2 million , primarily due to:

- customer growth in ATCO Gas;
- Calgary Stores Block Decision and Red Deer Operating Centre Decision (refer to Regulatory Matters – ATCO Gas section); and
- colder temperatures in ATCO Gas.

This increase was partially offset by:

- a 2005 AEUB decision adjusting the 2001 and 2002 revenue requirements for changes in future income taxes recorded in ATCO Electric (refer to Regulatory Matters – ATCO Electric section); and
- lower sales per customer in ATCO Gas.

Operating expenses for the year ended December 31, 2006, **decreased** by $115.5 million to $601.4 million, primarily due to:

- reduced natural gas supply costs in 2006 as ATCO Gas ceased selling natural gas from its natural gas storage facilities on March 31, 2005, in accordance with AEUB directives.

Power Generation

Revenues from the Power Generation Business Group for the three months ended December 31, 2006, **increased** by $15.7 million to $226.7 million, primarily due to:

- higher availability (due to a planned outage in 2005), improved merchant performance, and higher natural gas fuel purchases recovered on a "no-margin" basis in ATCO Power's U.K. operations.

This increase was partially offset by:

- lower Power Purchase Arrangement ("PPA") tariffs due to declining rate bases at Alberta Power (2000)'s generating plants and a decline in the return on common equity rate (2006 – 8.75%, 2005 – 9.49%) that is based on long term Government of Canada bond yields plus 4.5%.

Revenues for the year ended December 31, 2006, **increased** by $28.8 million to $799.5 million, primarily due to:

- improved merchant performance, higher natural gas fuel purchases recovered on a "no-margin" basis, and higher availability (due to a planned outage in 2005) in ATCO Power's U.K. operations; and
- higher revenues in ATCO Power's Alberta generating plants due to higher Alberta Power Pool prices.

This increase was partially offset by:

- impact of lower U.K. and Australia exchange rates on conversion of revenues to Canadian dollars in ATCO Power; and
- lower PPA tariffs due to declining rate bases at Alberta Power (2000)'s generating plants and a decline in the return on common equity rate (2006 – 8.75%, 2005 – 9.49%) that is based on long term Government of Canada bond yields plus 4.5%.

Earnings for the three months ended December 31, 2006, **increased** by $0.2 million to $36.9 million, primarily due to:

- higher earnings in ATCO Power's Alberta generating plants due to higher spark spreads realized on sales of electricity in the Alberta market; and
- improved merchant performance and higher availability (due to a planned outage in 2005) in ATCO Power's U.K. operations.

This increase was partially offset by:

- higher maintenance expenses due to a planned outage in 2006 at Alberta Power (2000)'s Battle River generating plant; and
- a settlement with a supplier was recorded in the fourth quarter of 2005 for damages due to equipment defects in ATCO Power's U.K. operations..

Alberta Power Pool electricity prices for the three months ended December 31, 2006, averaged $116.81 per megawatt hour, compared to average prices of $117.07 per megawatt hour for the corresponding period in 2005. Natural gas prices for the three months ended December 31, 2006, averaged $6.55 per gigajoule, compared to average prices of $10.77 per gigajoule for the corresponding period in 2005. The consequence of these changes in electricity and natural gas prices was an average spark spread of $67.66 per megawatt hour for the three months ended December 31, 2006, compared to $36.31 per megawatt hour for the corresponding period in 2005.

Spark spread is related to the difference between Alberta Power Pool electricity prices and the marginal cost of producing electricity from natural gas. These spark spreads are based on an approximate industry heat rate of 7.5 gigajoules per megawatt hour.

Changes in spark spread affect the results of approximately 406 megawatts of plant capacity owned in Alberta by ATCO Power and Alberta Power (2000) out of a total Alberta owned capacity of approximately 1,709 megawatts and a world wide owned capacity of approximately 2,474 megawatts.

On January 1, 2006, the Alberta Balancing Pool announced the sale of its interest in the PPA for Alberta Power (2000)'s Sheerness generating plant to TransCanada Energy Ltd. On May 8, 2006, EPCOR Utilities Inc. announced the sale of its interest in the PPA for Alberta Power (2000)'s Battle River generating plant to ENMAX Corporation. These sales are not expected to have a material impact on the Corporation's operations or earnings.

Alberta Power (2000) continued to operate the Rainbow generating plant during 2006 and the electricity generated was sold to the Alberta Power Pool. Alberta Power (2000) had one year after the expiry of the PPA for the Rainbow generating plant (December 31, 2005) to determine whether to decommission the plant in order to fully recover plant decommissioning costs or to continue to operate the plant. The Alberta Electric System Operator ("AESO") and Alberta Power (2000) are currently negotiating a contract that, if executed, will result in Alberta Power (2000) continuing to operate the plant and be responsible for future decommissioning costs. Alberta Power (2000) has filed an application with the AEUB to decommission the plant and thereby preserve Alberta Power (2000)'s rights to fully recover plant decommissioning costs in the event negotiations with the AESO are unsuccessful.

Earnings for the year ended December 31, 2006, **increased** by $14.0 million to $119.2 million, primarily due to:

- higher earnings in ATCO Power's Alberta generating plants due to higher spark spreads realized on sales of electricity in the Alberta market;
- improved merchant performance and higher availability (due to a planned outage in 2005) in ATCO Power's U.K. operations; and
- $7.2 million adjustment in the second quarter of 2006 for ATCO Power to reflect recent tax changes (refer to Recent Changes in Income Taxes and Rates section).

This increase was partially offset by:

- H.R. Milner Income Tax Reassessment (refer to H.R. Milner Income Tax Reassessment section); and
- lower PPA tariffs due to declining rate bases at Alberta Power (2000)'s generating plants and a decline in the return on common equity rate (2006 – 8.75%, 2005 – 9.49%) that is based on long term Government of Canada bond yields plus 4.5%.

Alberta Power Pool electricity prices in 2006, averaged $80.79 per megawatt hour, compared to average prices of $70.36 per megawatt hour in 2005. Natural gas prices in 2006, averaged $6.17 per gigajoule, compared to average prices of $8.27 per gigajoule in 2005. The consequence of these changes in electricity and natural gas prices was an average spark spread of $34.52 per megawatt hour in 2006, compared to $8.32 per megawatt hour in 2005.

Operating expenses for the year ended December 31, 2006, **increased** by $10.9 million to $431.3 million, primarily due to:

- higher fuel costs due to the expiry in December 2005 of the PPA for Alberta Power (2000)'s Rainbow generating plant. Fuel costs were the responsibility of the PPA counterparty.

At December 31, 2006, all of ATCO Power's non-regulated independent generating plants were in service.

During the three months ended December 31, 2006, Alberta Power (2000)'s **deferred availability incentive** account **decreased** by $41.0 million to $39.6 million. The decrease was due to availability penalties paid associated with the planned outage in 2006 for Alberta Power (2000)'s Battle River generating plant which occurred during a period of high Alberta Power Pool electricity prices as well as normal amortization. During the three months ended December 31, 2006, the amortization of deferred availability incentives, recorded in revenues, was **unchanged** at $2.7 million as compared to the same period in 2005.

During the year ended December 31, 2006, Alberta Power (2000)'s **deferred availability incentive** account **decreased** by $20.1 million to $39.6 million. The decrease was due to additional availability penalties paid associated with the planned outage in the fourth quarter of 2006 for Alberta Power (2000)'s Battle River generating plant which occurred during a period of high Alberta Power Pool electricity prices as well as normal amortization. During the year ended December 31, 2006, the amortization of deferred availability incentives, recorded in revenues, **increased** by $1.7 million to $10.6 million as compared to 2005.

Global Enterprises

Revenues from the Global Enterprises Business Group for the three months ended December 31, 2006, **decreased** by $26.0 million to $173.9 million, primarily due to:

- lower recovery of natural gas costs in revenues due to customers supplying shrinkage gas in ethane extraction operations in ATCO Midstream; and
- lower volumes of natural gas purchased and resold for natural gas liquids extraction in ATCO Midstream.

Revenues for the year ended December 31, 2006, **decreased** by $11.8 million to $667.2 million, primarily due to:

- lower recovery of natural gas costs in revenues due to customers supplying shrinkage gas in ethane extraction operations in ATCO Midstream;
- lower volumes of natural gas purchased and resold for natural gas liquids extraction in ATCO Midstream; and
- lower business activity in ATCO Frontec.

This decrease was partially offset by:

- higher storage revenues due to higher capacity leased, and the timing and demand of storage capacity sold, by ATCO Midstream; and
- increased sales of natural gas to affiliates by ATCO Midstream.

Earnings for the three months ended December 31, 2006, were **substantially unchanged.**

Earnings for the year ended December 31, 2006, **increased** by $22.2 million to $101.0 million, primarily due to:

- higher margins received for natural gas liquids, higher storage earnings due to higher capacity leased, and the timing and demand of storage capacity sold by ATCO Midstream.

Operating expenses for the year ended December 31, 2006, **decreased** by $42.6 million to $490.5 million, primarily due to:

- lower volumes of natural gas purchased for natural gas liquids extraction in ATCO Midstream;
- lower natural gas prices for shrinkage gas used in natural gas liquids extraction in ATCO Midstream; and
- lower business activity in ATCO Frontec.

On January 30, 2007, ATCO Frontec announced it had been awarded a contract with the United Nations to provide camp support and food services to the United Nations Mission in Kosovo.

Corporate and Other

Earnings from the Corporate and Other segment for the three months ended December 31, 2006 **increased** by $1.0 million to $(6.5) million, primarily due to:

- higher short term interest rates on larger cash balances.

Earnings for the year ended December 31, 2006 **increased** by $11.8 million to $(11.7) million, primarily due to:

- decreased share appreciation rights expense due to changes in Canadian Utilities Limited Class A share and ATCO Ltd. Class I Non-Voting Share prices since December 31, 2005; and
- higher short term interest rates on larger cash balances.

REGULATORY MATTERS

Regulated operations are conducted by wholly owned subsidiaries of Canadian Utilities' wholly owned subsidiary, CU Inc.:

- ATCO Electric and its subsidiaries Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical;
- the ATCO Gas and ATCO Pipelines divisions of ATCO Gas and Pipelines Ltd.; and
- the generating plants of Alberta Power (2000).

Regulated operations in Alberta (except for the generating plants of Alberta Power (2000)) are subject to a generic cost of capital regime:

- in July 2004, the AEUB issued the generic cost of capital decision which established, among other things:
    - a standardized approach for each utility company regulated by the AEUB for determining the rate of return on common equity;
        - rate of return adjusted annually by 75% of the change in long term Government of Canada bond yield as forecast; and
        - adjustment mechanism similar to the method the National Energy Board uses in determining its formula based rate of return;
    - the capital structure for each utility regulated by the AEUB.
- in November 2005, the AEUB announced a generic return on common equity of 8.93% for 2006;
- in January 2006, the AEUB clarified that the generic return on equity determined on an annual basis in accordance with the generic cost of capital decision should apply to each year of the test period in the companies' applications. If no rate applications are filed for a particular year, then there will be no adjustment to the common equity rate of return for that year; and
- in November 2006, the AEUB announced a generic return on common equity of 8.51% for 2007.

In June 2005, as part of their rate applications, ATCO Electric and ATCO Gas submitted a filing to the AEUB that addressed certain common matters. ATCO Pipelines was also a party to this filing as the concerns were common to all three utilities:

- this filing included evidence regarding:
  - the appropriate ratemaking approach in the determination of utility revenue requirements;
  - treatment of pension costs, executive compensation and head office rent expense; and
  - the continued use of preferred shares as a form of financing for the three utilities;
- AEUB heard this filing in May 2006; and
- on October 11, 2006, the AEUB issued a decision (the "Common Matters Decision") which resulted in no significant impact on earnings. Among other things, the decision upheld ATCO's treatment of pension costs and approved the continued use of preferred shares. In addition, the decision approved minimal changes to head office rent expense and executive compensation.

ATCO Electric

In March 2006, the AEUB issued a decision on ATCO Electric's 2005 and 2006 General Tariff Application ("ATCO Electric GTA Decision"):

- which established, among other things, the amount of revenue to be collected in 2005 and 2006 from customers for transmission and distribution services, and confirmed the interim refundable rates approved by the AEUB in July 2005 (distribution services) and September 2005 (transmission services);
- ATCO Electric's 2005 earnings negatively impacted by $1.3 million, recorded in first quarter of 2006;
- ATCO Electric's 2006 earnings reduced by an additional $1.6 million, as compared to 2005 earnings, recorded throughout 2006; and
- return on common equity confirmed according to AEUB standardized rate of return methodology – 9.5% in 2005 and 8.93% in 2006.

In May 2006, the AEUB issued a decision on ATCO Electric's 2003-2004 Regulated Rate Option Tariff Non-Energy Rates application dated November 2002:

- this decision approved, on an interim refundable basis, the collection in 2006 of a shortfall of $2.7 million for 2003 and $2.2 million for 2004 that was not previously incorporated into customer rates;
- the amounts approved for collection are subject to the outcome of an existing process regarding the pricing of services provided by ATCO I-Tek; and
- the impact of this decision increased ATCO Electric's 2006 earnings by $1.9 million and was recorded in the second quarter of 2006.

In August 2002, the AEUB issued a decision in which it denied ATCO Electric's application to adjust its 2001 and 2002 transmission and distribution revenue requirements by $4.6 million for changes in the amounts of future income taxes recorded:

- in May 2005, the AEUB changed its August 2002 decision and allowed ATCO Electric to increase its revenues and earnings by $4.6 million. The impact of this decision was recorded in the second quarter of 2005.

In August 2006, the AEUB approved the first phase of the AESO's application for the need to improve transmission infrastructure in northwest Alberta:

- AEUB decision grants the AESO approval to assign approximately $300 million in projects to the Transmission Facility Owner, ATCO Electric;
- once assigned by the AESO, ATCO Electric will prepare and file facility applications with the AEUB. Construction will commence once approval to proceed is received from the AEUB; and
- the entire project was originally intended to be completed by 2009, but now is anticipated to be completed by 2011. As a result of price escalation caused by the change in completion date, coupled with the increasing costs of construction in Alberta, the entire project is now estimated to cost $400 million.

In November 2006, ATCO Electric filed a general tariff application with the AEUB for the 2007 and 2008 test years:

- requesting, among other things, increased revenues to recover increased financing, depreciation and operating costs associated with increased rate base in Alberta;
- a decision from the AEUB on the general tariff application is not expected until late 2007;

- in November 2006, ATCO Electric filed an application requesting interim refundable rates for transmission and distribution operations, pending the AEUB's decision on the general tariff application; and
- on December 19, 2006, ATCO Electric received a decision from the AEUB approving interim refundable rate increases amounting to 50% of ATCO Electric's requested increases for transmission and distribution operations.

ATCO Gas

In January 2006, the AEUB issued a decision on ATCO Gas' 2005, 2006 and 2007 General Rate Application ("ATCO Gas GRA Decision"):
- which, among other things, established the amount of revenue to be collected over the period 2005 to 2007 from customers for natural gas distribution service and approved a return on common equity as determined by the AEUB's standardized rate of return methodology – 9.5% in 2005, 8.93% in 2006 and 8.51% in 2007;
- the final impact of the decision will not be known until a subsequent regulatory process is finalized; and
- a decision from the AEUB with respect to a second regulatory process that was pending at the end of 2005 was received on October 11, 2006; the effect of this decision on the earnings of the Corporation was not material.

In May 2006, the City of Calgary filed a Review and Variance application with the AEUB for the ATCO Gas GRA Decision:
- the application alleges that the AEUB made errors in the ATCO Gas GRA Decision related to the calculation of working capital needed by ATCO Gas to operate its Carbon natural gas storage facility; and
- the AEUB issued its decision on January 17, 2007, denying the City of Calgary's application.

In October 2006, ATCO Gas also filed a Review and Variance application with the AEUB for the ATCO Gas GRA Decision:
- the application alleges that the AEUB made errors in the ATCO Gas GRA Decision related to the approved level of administrative expenses;
- in December 2006, the AEUB issued a decision in which it acknowledged an error for a portion of the administrative expenses in question; and
- a further AEUB decision on the remainder of this application is expected in the 2nd quarter of 2007.

In October 2001, the AEUB approved the sale by ATCO Gas of certain properties in the City of Calgary, known as the Calgary Stores Block, for $6.6 million (excluding costs of disposition). As a result of this decision (the "Calgary Stores Block Decision"):
- $4.1 million of the proceeds were allocated by the AEUB to customers and $1.8 million to ATCO Gas;
- ATCO Gas appealed the decision to the Alberta Court of Appeal which overturned the decision and directed the AEUB to allocate $5.4 million of the proceeds to ATCO Gas;
- City of Calgary appealed this decision to the Supreme Court of Canada, which also granted ATCO Gas leave to cross-appeal the decision;
- the Supreme Court of Canada rendered its decision on February 9, 2006, dismissing the City of Calgary's appeal and allowing ATCO Gas' cross-appeal. The AEUB was directed to issue a new decision in accordance with the Supreme Court's ruling;
- ATCO Gas requested that the AEUB address the Supreme Court of Canada decision; and
- the AEUB complied with the Supreme Court of Canada decision on August 11, 2006, and ATCO Gas recorded additional net proceeds totaling $4.1 million from the sale and increased earnings of $3.7 million after income taxes in the third quarter of 2006.

ATCO Gas owns a 43.5 petajoule natural gas storage facility located at Carbon, Alberta. ATCO Gas has leased the entire storage capacity of the facility to ATCO Midstream. ATCO Gas has taken the position that the facility is no longer required for utility service and should be removed from regulation. In the process of obtaining AEUB approval, the following events are significant:
- in July 2004, the AEUB initiated a written process to consider its role in regulating the operations of the facility;

- in June 2005, the AEUB issued a decision with respect to this process. In addition to addressing other matters, the decision found that the AEUB has the authority, when necessary in the public interest, to direct a utility to utilize a particular asset in a specific manner, even over the objection of the utility;
- ATCO Gas filed for leave to appeal the decision with the Alberta Court of Appeal;
- in October 2005, the AEUB established processes to review the use of the facility for utility purposes;
- a hearing to review the use of the facility for revenue generation was held in April 2006 and a hearing to review the use of the facility for load balancing was held in June 2006. On October 11, 2006 the AEUB issued a decision confirming ATCO Gas' position that the facility is no longer required for utility service with respect to the use of the facility for load balancing purposes. The City of Calgary has filed a leave to appeal and a review and variance application of this decision; and
- on February 5, 2007, the AEUB issued a decision in which it determined that a legitimate utility use for the facility is that it be used for purposes of generating revenues to offset customer rates. The AEUB has directed ATCO Gas to continue to lease the entire storage capacity of the facility to ATCO Midstream. The AEUB will conduct a further process to determine if it is appropriate that 100% or some lesser portion of this facility should be used to offset customer rates. (Refer to Business Risks - Regulated Operations - Carbon Natural Gas Storage Facility section).

ATCO Gas has filed an application with the AEUB to address, among other things, corrections required to historical transportation imbalances (the process whereby third party natural gas supplies are reconciled to amounts actually shipped in the Corporation's pipelines) that have impacted ATCO Gas' deferred gas account:

- in April 2005, the AEUB issued a decision resulting in a 15% decrease in the transportation imbalance adjustments sought by ATCO Gas. The decision resulted in a decrease to ATCO Gas' 2005 revenues and earnings of $1.8 million and $1.2 million, respectively; and
- City of Calgary filed for leave to appeal the AEUB's decision. ATCO Gas filed a cross appeal of the AEUB's decision. The leave to appeal was heard by the Alberta Court of Appeal on April 18, 2006. On July 7, 2006 the Alberta Court of Appeal issued its decision granting the City of Calgary's leave to appeal on the question of whether the AEUB erred in law or jurisdiction in assuming that it had the authority to allow recovery in 2005, for costs relating to prior years. ATCO Gas' cross appeal was denied. A hearing with the Alberta Court of Appeal has been scheduled for April 13, 2007.

In October 2005, ATCO Gas filed an application with the AEUB to approve the sale of its Red Deer Operating Centre:

- in December 2005, the AEUB approved the sale and deferred its decision on the distribution of net proceeds of $1.0 million until the Supreme Court of Canada rendered a judgment in the appeal regarding the Calgary Stores Block disposition and allocation of proceeds discussed above;
- the Supreme Court of Canada rendered its decision on the Calgary Stores Block matter on February 9, 2006;
- in February 2006, ATCO Gas submitted a filing to the AEUB to approve the allocation of the net proceeds;
- on March 16, 2006, the AEUB suspended the process convened to approve allocation of the net proceeds pending resolution of certain issues arising in connection with the Supreme Court's Calgary Stores Block decision. The net proceeds of the sale remained in trust pending AEUB approval; and
- on August 16, 2006, ATCO Gas requested that the process re-convene in light of the AEUB's approval of the Calgary Stores Block application. The AEUB issued a call for comments which concluded on September 14, 2006 and on December 13, 2006 the AEUB issued a decision approving the distribution of proceeds to ATCO Gas resulting in increased revenue of $1.0 million and earnings of $0.7 million for ATCO Gas.

ATCO Pipelines

The AEUB has delayed its review of the competitive natural gas pipeline issues under AEUB jurisdiction until 2007. This review is expected to address competitive issues between ATCO Pipelines and NOVA Gas Transmission Ltd.

Other Matters

The Corporation has a number of other regulatory filings and regulatory hearing submissions before the AEUB for which decisions have not been received. The outcome of these matters cannot be determined at this time.

LIQUIDITY AND CAPITAL RESOURCES

Funds generated by operations provides a substantial portion of the Corporation's cash requirements. Additional cash requirements are met externally through bank borrowings and the issuance of long term and non-recourse debt and preferred shares. Commercial paper borrowings and short term bank loans are used to provide flexibility in the timing and amounts of long term financing.

Funds generated by operations for the three months ended December 31, 2006, **decreased** by $19.4 million to $168.4 million, primarily due to:

- decreased availability incentives in Alberta Power (2000), primarily due to availability penalties paid associated with the planned outage in 2006 for the Battle River generating plant which occurred during a period of high Alberta Power Pool electricity prices.

This decrease was partially offset by:

- increased earnings.

Funds generated by operations for the year ended December 31, 2006, **decreased** by $1.8 million to $657.5 million, primarily due to:

- lower proceeds received from the TXU Europe Settlement (refer to TXU Europe Settlement section); and
- decreased availability incentives in Alberta Power (2000), primarily due to availability penalties paid associated with the planned outage in 2006 for the Battle River generating plant which occurred during a period of high Alberta Power Pool electricity prices.

This decrease was partially offset by:

- increased earnings.

Investing activities for the three months ended December 31, 2006, **increased** by $0.3 million to $160.6 million, primarily due to:

- changes in non-cash working capital.

This increase was partially offset by:

- increased contributions by utility customers for extensions to plant.

Purchase of property, plant and equipment for the three months ended December 31, 2006, **increased** by $2.8 million to $184.0 million, primarily due to:

- increased investment in regulated electric distribution and transmission projects.

This increase was partially offset by:

- decreased investment in regulated natural gas distribution projects.

Investing activities for the year ended December 31, 2006, **increased** by $57.1 million to $527.5 million, primarily due to:

- 2005 proceeds on the transfer of the retail energy supply businesses;
- increased capital expenditures;
- changes in non-cash working capital; and
- H.R. Milner Income Tax Reassessment (refer to H.R. Milner Income Tax Reassessment section).

This increase was partially offset by:

- increased contributions by utility customers for extensions to plant; and
- changes in non-current deferred electricity costs.

Purchase of property, plant and equipment for the year ended December 31, 2006, **increased** by $41.0 million to $567.7 million, primarily due to:

- increased investment in regulated electric distribution and transmission and regulated natural gas transportation projects.

This increase was partially offset by:

- decreased investment in regulated natural gas distribution projects.

During the three months ended December 31, 2006, the Corporation **issued**:

- $160.0 million of 4.801% Debentures due November 22, 2021; and
- $160.0 million of 5.032% Debentures due November 20, 2036.

During the three months ended December 31, 2006, the Corporation **redeemed**:

- $175.0 million of 4.84% Debentures due November 6, 2006; and
- $12.6 million of non-recourse long term debt.

These changes resulted in a **net debt increase** of $132.4 million.

During the year ended December 31, 2006, the Corporation **issued**:

- $160.0 million of 4.801% Debentures due November 22, 2021;
- $160.0 million of 5.032% Debentures due November 20, 2036; and
- $35.5 million of other long term debt.

During the year ended December 31, 2006, the Corporation **redeemed**:

- $175.0 million of 4.84% Debentures due November 6, 2006; and
- $64.6 million of non-recourse long term debt.

These changes resulted in a **net debt increase** of $115.9 million.

Net purchase of Class A non-voting shares for the three months ended December 31, 2006, **decreased** by $4.6 million to $1.9 million, primarily due to decreased share purchases in 2006.

Net purchase of Class A non-voting shares for the year ended December 31, 2006, **increased** by $64.8 million to $67.5 million, primarily due to increased share purchases in 2006.

Foreign currency translation for the three months ended December 31, 2006, positively impacted the Corporation's cash position by $11.4 million to $11.6 million, primarily as a result of:

- changes in the U.K. exchange rate which resulted in an increase in the value of cash balances denominated in U.K. pounds when translated into Canadian dollars.

Foreign currency translation for the year ended December 31, 2006, positively impacted the Corporation's cash position by $27.5 million to $16.3 million, primarily as a result of:

- changes in the U.K. exchange rate which resulted in an increase in the value of cash balances denominated in U.K. pounds when translated into Canadian dollars.

At December 31, 2006, the Corporation had the following credit lines that enable it to obtain funding for general corporate purposes.

($ Millions)	Total	Used	Available
Long term committed	326.0	47.4	278.6
Short term committed	600.0	14.0	586.0
Uncommitted	69.1	7.1	62.0
Total	995.1	68.5	926.6

The amount and timing of future financings will depend on market conditions and the specific needs of the Corporation.

Capital expenditures to maintain capacity, meet planned growth and fund future development activities are expected to be approximately $725 million in 2007. The majority of these expenditures are uncommitted and relate primarily to utility operations.

Contractual obligations for the next five years and thereafter are as follows:

Contractual Obligations	Total	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
		Payments Due by Period			
($ Millions)					
Long term debt	2,411.5	54.5	225.0	272.0	1,860.0
Non-recourse long term debt	686.0	59.3	150.3	124.2	352.2
Operating leases	61.6	18.5	24.6	13.7	4.8
Purchase obligations:					
ATCO Gas natural gas purchase contracts [1]	4.5	0.5	1.0	1.0	2.0
Alberta Power (2000) coal purchase contracts [2]	607.7	47.7	99.2	105.2	355.6
ATCO Power natural gas fuel supply contracts [3]	248.1	52.4	104.8	74.0	16.9
ATCO Power operating and maintenance agreements [4]	198.2	21.2	45.3	38.4	93.3
Capital expenditures [5]	45.4	45.4	-	-	-
Other	7.8	7.8	-	-	-
Total	4,270.8	307.3	650.2	628.5	2,684.8

Notes:

(1) *ATCO Gas has ongoing obligations to purchase fixed quantities of natural gas from various gas producers at market prices that are in effect at the time the quantities are purchased. These obligations relate primarily to operational contracts pertaining to the Carbon natural gas storage facility, which was not included in the Transfer of the Retail Energy Supply Businesses to DEML and continues to be subject to AEUB regulation. Some of these obligations are for the life of the gas reserves. The estimated value of these purchase obligations is based on the market price of natural gas in effect on December 31, 2006, and assumes a remaining life of 10 years for the gas reserves commencing January 1, 2004. DEML has agreed to purchase the natural gas purchased under these contracts at the prices paid by ATCO Gas.*

(2) *Alberta Power (2000) has fixed price long term contracts to purchase coal for its coal-fired generating plants. These costs are recoverable pursuant to the power purchase arrangements.*

(3) *ATCO Power has various contracts to purchase natural gas for certain of its natural gas-fired generating plants. ATCO Power has long term offtake agreements with the purchasers of the electricity to recover 78% of these costs. The balance of 22%, related to ATCO Power's Barking generating plant, is currently being recovered through merchant sales in the U.K. electricity market. ATCO Power's merchant generating plants in Alberta do not have any long term contracts to purchase natural gas.*

(4) *ATCO Power has various contracts with suppliers to provide operating and maintenance services at certain of its generating plants.*

(5) *Various contracts to purchase goods and services with respect to capital expenditure programs.*

Current and long term future income tax liabilities of $195.0 million at December 31, 2006, are attributable to differences between the financial statement carrying amounts of assets and liabilities and their tax bases. These differences result primarily from recognizing revenue and expenses in different years for financial and tax reporting purposes. Future income taxes will become payable when such differences are reversed through the settlement of liabilities and realization of assets.

On May 20, 2005, the Corporation commenced a **normal course issuer bid** for the purchase of up to 3% of the outstanding Class A shares. The bid expired on May 19, 2006. Over the life of the bid, 348,100 shares were purchased, of which 195,600 were purchased in 2005 and 152,500 were purchased in 2006. On May 23, 2006, the Corporation commenced a new normal course issuer bid for the purchase of up to 5% of the outstanding Class A shares. The bid will expire on May 22, 2007. From May 23, 2006, to February 16, 2007, 1,679,700 shares have been purchased, all of which were purchased in 2006.

It is the policy of the Corporation to **pay dividends** quarterly on its Class A and Class B shares. For the first quarter of 2006, the quarterly dividend payment on the Corporation's Class A and Class B shares **increased** by $0.01 to $0.285 per share. The quarterly dividend payment for the second quarter remained unchanged at $0.285 per share. For the third quarter of 2006, the quarterly dividend was increased by $0.005 to $0.29 per share. The Corporation also approved a one-time special dividend of $0.25 per share. Both the third quarter dividend of $0.29 per share and the one-time special dividend of $0.25 per share were paid on September 1, 2006, to shareholders of record on August 9, 2006. Based on approximately 126.3 million shares then outstanding, the one-time special dividend totaled approximately $31.6 million. The Corporation has increased its annual common share dividend each year since its inception as a holding company in 1972. The matter of an increase in the quarterly dividend is addressed by the Board of Directors in the first quarter of each year. For the first quarter of 2007, the quarterly dividend payment has been **increased** by $0.015 to $0.305 per share. The

payment of any dividend is at the discretion of the Board of Directors and depends on the financial condition of the Corporation and other factors.

On April 12, 2006, CU Inc. filed a **base shelf prospectus** which permits CU Inc. to issue up to an aggregate of $850.0 million of debentures over the twenty-five month life of the prospectus.

- on November 20, 2006, the Corporation issued $160.0 million of 4.801% Debentures due November 22, 2021, at a price of 100 to yield 4.801%, and $160.0 million of 5.032% Debentures due November 20, 2036, at a price of 100 to yield 5.032%. The proceeds of these issues were advanced to ATCO Electric, ATCO Gas and ATCO Pipelines and used to fund capital expenditures, repay indebtedness and for general corporate purposes.

OUTSTANDING SHARE DATA

At February 16, 2007, the Corporation had outstanding 81,462,286 Class A shares and 43,926,484 Class B shares.

The owners of the Class A shares and the Class B shares are entitled to share equally, on a share for share basis, in all dividends declared by the Corporation on either of such classes of shares as well as the remaining property of the Corporation upon dissolution. The owners of the Class B shares are entitled to vote and to exchange at any time each share held for one Class A share.

If a take-over bid is made for the Class B shares which would result in the offeror owning more than 50% of the outstanding Class B shares and which would constitute a change in control of the Corporation, owners of Class A shares are entitled, for the duration of the bid, to exchange their Class A shares for Class B shares and to tender such Class B shares pursuant to the terms of the take-over bid. Such right of exchange is conditional upon the completion of the take-over bid giving rise to the right of exchange, and if the take-over bid is not completed, then the right of exchange shall be deemed never to have existed. In addition, owners of Class A shares are entitled to exchange their shares for Class B shares of the Corporation if ATCO Ltd., the present controlling share owner of the Corporation, ceases to own or control, directly or indirectly, more than 10,000,000 of the issued and outstanding Class B shares of the Corporation. In either case, each Class A share is exchangeable for one Class B share, subject to changes in the exchange ratio for certain events such as a stock split or rights offering.

Of the 6,400,000 Class A shares reserved for issuance in respect of options under the Corporation's stock option plan, 2,626,800 Class A shares are available for issuance at December 31, 2006. Options may be granted to directors, officers and key employees of the Corporation and its subsidiaries at an exercise price equal to the weighted average of the trading price of the shares on the Toronto Stock Exchange for the five trading days immediately preceding the date of grant. The vesting provisions and exercise period (which cannot exceed 10 years) are determined at the time of grant. As of February 16, 2007, options to purchase 1,368,900 Class A shares were outstanding.

TRANSACTIONS WITH RELATED PARTIES

The Corporation's transactions with related parties are in the normal course of business and under normal commercial terms. For a description of these transactions, refer to Note 19 to the consolidated financial statements for the year ended December 31, 2006.

BUSINESS RISKS

The current Federal government favours a made in Canada approach to deal with climate change instead of the Kyoto Protocol which the previous government had ratified. The Corporation is unable to determine what impact the Clean Air Act may have on its operations as the Government of Canada has not yet provided industry specific details for its 2006 Climate Change Plan. While it is not certain, it is anticipated that the Corporation's PPA's relating to its coal-fired generating plants will allow the Corporation to recover any increased costs associated with the implementation of the Clean Air Act.

Regulated Operations

ATCO Electric, ATCO Gas and ATCO Pipelines are regulated primarily by the AEUB, which administers acts and regulations covering such matters as rates, financing, accounting, construction, operation and service area. The AEUB may approve interim rates or approve the recovery of costs on a placeholder basis, subject to final determination. These subsidiaries are subject to the normal risks faced by companies that are regulated. These risks include the approval by the AEUB of customer rates that permit a reasonable opportunity to recover on a timely basis the estimated costs of providing service, including a fair return on rate base. The Corporation's ability to recover the actual costs of providing service and to earn the approved rates of return depends on achieving the forecasts established in the rate-setting process.

Carbon Natural Gas Storage Facility

ATCO Gas leases the entire storage capacity of the Carbon natural gas storage facility to ATCO Midstream at AEUB approved placeholder rates. On February 5, 2007, the AEUB issued a decision to ATCO Gas that leaves in question these placeholder rates and the effect that these placeholder rates will have on future ATCO Gas revenues. (Refer to Regulatory Matters – ATCO Gas section).

Weather

Weather fluctuations have a significant impact on throughput in ATCO Gas. Since approximately 50% of ATCO Gas' delivery charge is recovered based on throughput, ATCO Gas' revenues and earnings are sensitive to weather. Weather that is 10% warmer or colder than normal temperatures impacts annual earnings by approximately $10.0 million.

ATCO I-Tek Services

ATCO Electric, ATCO Gas and ATCO Pipelines purchase information technology services, and ATCO Electric and ATCO Gas also purchase customer care and billing services, from ATCO I-Tek. The recovery of these costs in customer rates are subject to AEUB approval. Since 2003, the costs have been approved on a placeholder basis, and are subject to final AEUB approval after completion of an ongoing collaborative benchmarking process.

Transfer of the Retail Energy Supply Businesses

On May 4, 2004, ATCO Gas and ATCO Electric transferred their retail energy supply businesses to Direct Energy Marketing Limited and one of its affiliates (collectively "DEML"), a subsidiary of Centrica plc.

Although ATCO Gas and ATCO Electric transferred to DEML certain retail functions, including the supply of natural gas and electricity to customers and billing and customer care functions, the legal obligations of ATCO Gas and ATCO Electric remain if DEML fails to perform. In certain events (including where DEML fails to supply natural gas and/or electricity and ATCO Gas and/or ATCO Electric are ordered by the AEUB to do so), the functions will revert to ATCO Gas and/or ATCO Electric with no refund of the transfer proceeds to DEML by ATCO Gas and/or ATCO Electric.

Centrica plc, DEML's parent, has provided a $300 million guarantee, supported by a $235 million letter of credit in respect of DEML's obligations to ATCO Gas, ATCO Electric and ATCO I-Tek Business Services in respect of the ongoing relationships contemplated under the transaction agreements. However, there can be no assurance that the coverage under these agreements will be adequate to cover all of the costs that could arise in the event of a reversion of such functions.

The Corporation has provided a guarantee of ATCO Gas', ATCO Electric's and ATCO I-Tek Business Services' payment and indemnity obligations to DEML contemplated under the transaction agreements.

Late Payment Penalties on Utility Bills

As a result of decisions of the Supreme Court of Canada in Garland vs. Consumers' Gas Co., the imposition of late payment penalties on utility bills has been called into question. The Corporation is unable to determine at this time the impact, if any, that these decisions will have on the Corporation.

Alberta Power (2000)

Included in regulated operations are the generating plants of Alberta Power (2000), which were regulated by the AEUB until December 31, 2000, but are now governed by legislatively mandated PPA's that were approved by the AEUB. These plants are included in regulated operations primarily because the PPA's are designed to allow the owners of generating plants constructed before January 1, 1996, to recover their forecast fixed and variable costs and to earn a return at the rate specified in the PPA's. The plants will become deregulated upon the earlier of one year after the expiry of a PPA or a decision to continue to operate the plant. Alberta Power (2000) has one year after the expiry of a PPA to determine whether to decommission the generating plant in order to fully recover plant decommissioning costs or to continue to operate the plant. Each PPA is to remain in effect until the earlier of the last day of the estimated life of the related generating plant or December 31, 2020.

Substantially all the electricity generated by Alberta Power (2000) is sold pursuant to PPA's. Under the PPA's, Alberta Power (2000) is required to make the generating capacity for each generating unit available to the purchaser of the PPA for that unit. In return, Alberta Power (2000) is entitled to recover its forecast fixed and variable costs for that unit from the PPA purchaser, including a return on common equity equal to the long term Government of Canada bond rate plus 4.5% based on a deemed common equity ratio of 45%. Many of the forecast costs will be determined by indices, formulae or other means for the entire period of the PPA. Alberta Power (2000)'s actual results will vary and depend on performance compared to the forecasts on which the PPA's were based.

Under the terms of the PPA's, the Corporation is subject to an incentive/penalty regime related to generating unit availability. Incentives are paid to the Corporation by the PPA counterparties for availability in excess of predetermined targets, whereas penalties are paid by the Corporation to the PPA counterparties when the availability targets are not achieved.

Accumulated incentives in excess of accumulated penalties are deferred. For any of the individual PPA's, should accumulated incentives plus estimated future incentives exceed accumulated penalties plus estimated future penalties, the excess will be amortized to revenues on a straight-line basis over the remaining term of the PPA's. Should accumulated penalties plus estimated future penalties exceed accumulated incentives plus estimated future incentives, the shortfall will be expensed in the year the shortfall occurs.

At December 31, 2006, the Corporation had recorded $39.6 million of deferred availability incentives.

Fuel costs in Alberta Power (2000) are mostly for coal supply. To protect against volatility in coal prices, Alberta Power (2000) owns or has sufficient coal supplies under long term contracts for the anticipated lives of its Battle River and Sheerness coal-fired generating plants. These contracts are at prices that are either fixed or indexed to inflation.

Alberta Environment implemented mercury emission regulations in March 2006 for coal-fired generating plants. Owners of coal-fired generating plants are required to submit by April 1, 2007, proposals on capturing at least 70% of the mercury in the coal burned in their plants. The proposals for mercury emission reduction must be implemented by 2010. While it is not certain, it is anticipated that the Corporation's PPA's relating to its coal-fired generating plants will allow the Corporation to recover most of the costs associated with complying with the new regulation.

Measurement Inaccuracies in Metering Facilities

Measurement inaccuracies occur from time to time with respect to ATCO Electric's, ATCO Gas' and ATCO Pipelines' metering facilities. Measurement adjustments are settled between the parties based on the requirements of the Electricity and Gas Inspections Act (Canada) and applicable regulations issued pursuant thereto. There is a risk of disallowance of the recovery of a measurement adjustment if controls and timely follow up are found to be inadequate by the AEUB.

A recent AEUB decision applicable to ATCO Gas established a two year adjustment limitation period for inaccuracies in gas supply costs, including measurement inaccuracies in metering facilities. The AEUB stated that it will consider specific applications for adjustments beyond the two year limitation period.

Non-Regulated Operations

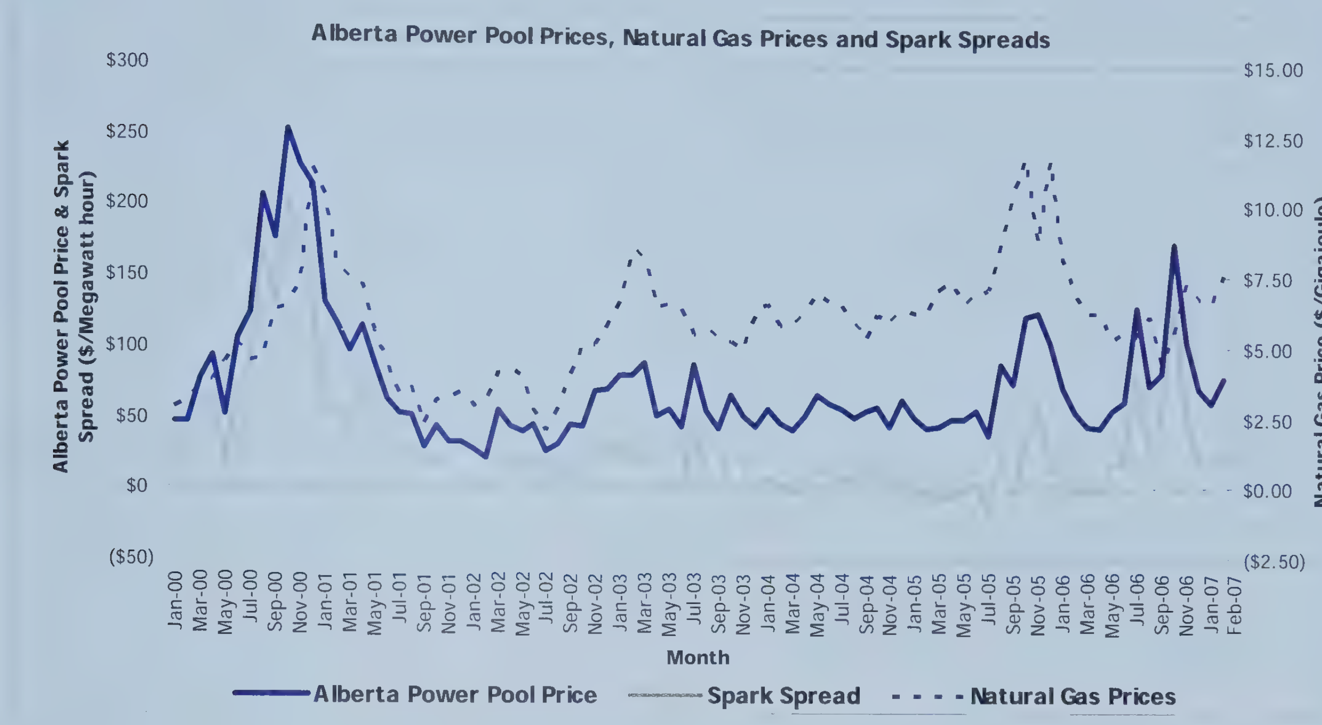
The Corporation's non-regulated operations are complementary to its traditional regulated businesses and are related to them in terms of skills, knowledge and experience. The Corporation accounts for its non-regulated operations separately from its regulated operations. The Corporation's non-regulated operations are subject to the risks faced by any commercial enterprise in those industries and in those countries in which they operate.

ATCO Power

The Corporation's portfolio of non-regulated electric generating plants is made up of gas-fired cogeneration, gas-fired combined cycle, gas-fired simple cycle, and small hydro plants. The majority of operating income from power generation operations is derived through long term power, steam and transmission support agreements. Where long term agreements are in place, the purchaser assumes the fuel supply and price risks and the Corporation, under these agreements, assumes the operating risks.

ATCO Power's generating plants include high efficiency gas-fired cogeneration plants, with associated on-site steam and power tolling arrangements, and gas-fired peaking and hydroelectric plants with underlying transmission support agreements. In 2006, sales from approximately 71% of ATCO Power's generating capacity were subject to long term agreements, while the remaining 29% consisted primarily of sales to the Alberta Power Pool and the U.K. merchant power market. In 2007, these percentages are expected to be approximately the same. These sales are dependent on prices in the Alberta electricity spot market and in the U.K. merchant power market. The majority of the electricity sales to the Alberta Power Pool are from gas-fired generating plants, and as a result operating income is affected by natural gas prices. During peak electricity usage hours in Alberta, a good correlation exists between electricity spot prices and natural gas spot prices. During off-peak hours, there is less correlation. The correlation is expected to increase in the future as customer load grows and older plants are decommissioned.

Alberta Power Pool electricity prices, natural gas prices and related spark spreads can be very volatile, as shown in the following graph, which illustrates a range of prices experienced during the period January 2000 to February 2007.



Changes in Alberta Power Pool electricity prices, natural gas prices and related spark spreads may have a significant impact on the Corporation's earnings and cash flow from operations in the future. It is the Corporation's policy to continually monitor the status of its non-regulated electrical generating capacity that is not subject to long term commitments.

Since October 2004, the output from ATCO Power's Barking generating plant previously sold to TXU Europe (refer to TXU Europe Settlement section) has been sold into the U.K. power exchange market. In the U.K., electricity generators, on average, sell over 90% of their output to electricity suppliers in bilateral contracts, use power exchanges for approximately 7% of their output, and sell the remaining 2-3% via the Balancing Mechanism. Approximately 40% of the electricity generated is supplied from natural gas-fired generating plants, and earlier this year the market experienced an increase in electricity prices due to the increased world prices for natural gas. Since then natural gas prices have softened with additional natural gas infrastructure coming on stream and the slightly lower oil prices. Nevertheless, the Barking generating plant has a long term, fixed price gas purchase agreement and, as a result, has been able to experience increased margins due to the high market prices for electricity. Changes in the U.K. market electricity prices may have an impact on the Corporation's earnings and cash flow from operations in the future.

ATCO Power has financed its non-regulated electrical generating capacity on a non-recourse basis. In these projects, the lender's recourse in the event of default is limited to the business and assets of the project in question, which includes the Corporation's equity therein. Canadian Utilities Limited has provided a number of guarantees related to ATCO Power's obligations under non-recourse loans associated with certain of its projects. The guarantees outstanding at December 31, 2006, are described in Note 12 to the consolidated financial statements for the year ended December 31, 2006. To date, Canadian Utilities Limited has not been required to pay any of its guaranteed obligations.

ATCO Midstream

Timing, capacity and demand of ATCO Midstream's storage business as well as changes in market conditions may impact the Corporation's earnings and cash flow from storage operations.

ATCO Midstream extracts ethane and other natural gas liquids from natural gas streams at its extraction plants. These products are sold under either long term cost of service arrangements or market based arrangements. Changes in market conditions may impact the Corporation's earnings and cash flow from natural gas liquids extraction operations.

ATCO Frontec

ATCO Frontec's operations include providing support to military agencies in foreign locations which may be subject to political risk.

On December 23, 2005, the Government of Canada filed a claim in the amount of $70 million which alleges that the Corporation is liable for the destruction of property owned by the Governments of Canada and the United States. The Corporation believes that the claim is defensible and, in any event, has sufficient insurance coverage in place to cover any material amounts that might become payable as a result of the claim. Accordingly, the claim is not expected to have any material impact on the financial position of the Corporation.

A fuel spill occurred in January 2007 at the Brevoort Island, Northwest Territories radar site maintained by Nasittuq Corporation, a corporation jointly owned by ATCO Frontec and Pan Arctic Inuit Logistics Corporation. The Corporation believes that it has sufficient insurance coverage in place to cover any material amounts that might become payable as a result of the fuel spill. Accordingly, this spill is not expected to have any material impact on the financial position of the Corporation.

CONTINGENCIES

The Corporation is party to a number of disputes and lawsuits in the normal course of business. The Corporation believes that the ultimate liability arising from these matters will have no material impact on the consolidated financial statements.

HEDGING

In conducting its business, the Corporation uses various instruments, including forward contracts, swaps and options, to manage the risks arising from fluctuations in exchange rates, interest rates and commodity prices. All such instruments are used only to manage risk and not for trading purposes. For details on the financial instruments in place at December 31, 2006, refer to Note 21 to the consolidated financial statements for the year ended December 31, 2006.

OFF-BALANCE SHEET ARRANGEMENTS

At December 31, 2006, unrecorded future income tax liabilities of the regulated operations amounted to $141.3 million and unrecorded future income tax assets of other operations amounted to $0.5 million. The liabilities include $14.6 million in respect of Alberta Power (2000)'s generating plants, which will be recovered through future payments received in respect of the PPA's. There are tax loss carryforwards of $0.4 million for Canadian subsidiary corporations and $7.6 million for a foreign subsidiary corporation for which no tax benefit has been recorded. The losses for Canadian subsidiary corporations begin to expire in 2010 and the losses for the foreign subsidiary corporation do not expire. For additional information on the Corporation's unrecorded future income tax liabilities, refer to Note 7 to the consolidated financial statements for the year ended December 31, 2006.

Other than the financial instruments discussed under "Hedging", the Corporation does not have any off-balance sheet arrangements that have, or are likely to have, a current or future effect on the results of operations or financial condition, including, without limitation, such considerations as liquidity and capital resources.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the Corporation's consolidated financial statements in accordance with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the year. On an on-going basis, management reviews its estimates, particularly those related to depreciation and amortization methods, useful lives and impairment of long-lived assets, amortization of deferred availability incentives, asset retirement obligations and employee future benefits, using currently available information. Changes in facts and circumstances may result in revised estimates, and actual results could differ from those estimates. The Corporation's critical accounting estimates are discussed below.

Deferred Availability Incentives

As noted in the Business Risks section, Alberta Power (2000) is subject to an incentive/penalty regime related to generating unit availability. As at December 31, 2006, the Corporation had recorded $39.6 million of deferred availability incentives. The amortization of deferred availability incentives, which was recorded in revenues, amounted to $10.6 million in 2006.

The amount to be amortized is dependent upon estimates of future generating unit availability and future electricity prices over the term of the PPA's. Each quarter, the Corporation uses these estimates to forecast high case, low case and most likely scenarios for the incentives to be received from, less penalties to be paid to, the PPA counterparties. These forecasts are added to the accumulated unamortized deferred availability incentives outstanding at the end of the quarter; the resulting total is divided by the remaining term of the PPA to arrive at the amortization for the quarter.

Compared to the most likely scenario recorded in revenues for the year, the high case scenario would have resulted in higher revenues of approximately $5.0 million, whereas the low case scenario would have resulted in lower revenues of approximately $4.6 million.

Employee Future Benefits

The expected long term rate of return on pension plan assets is determined at the beginning of the year on the basis of the long bond yield rate plus an equity and management premium that reflects the plan asset mix. Actual balanced fund performance over a longer period suggests that this premium is about 1%, which, when added to the long bond yield rate of 5.1% at the beginning of 2006, resulted in an expected long term rate of return of 6.1% for 2006. This methodology is supported by actuarial guidance on long term asset return assumptions for the Corporation's defined benefit pension plans, taking into account asset class returns, normal equity risk premiums, and asset diversification effect on portfolio returns.

Expected return on plan assets for the year is calculated by applying the expected long term rate of return to the market related value of plan assets, which is the average of the market value of plan assets at the end of the preceding three years. The expected long term rate of return has declined over the past five years, from 8.1% in 2001 to 6.1% in the year ended December 31, 2006. The result has been a decrease in the expected return on plan assets and a corresponding increase in the cost of pension benefits. In addition, the actual return on plan assets over the same period has been lower than expected (i.e., an experience loss), which is also contributing to an increase in the cost of pension benefits as losses are amortized to earnings.

The liability discount rate that is used to calculate the cost of benefit obligations reflects market interest rates on high quality corporate bonds that match the timing and amount of expected benefit payments. The liability discount rate has also declined over the same five year period, from 6.9% at the end of 2001 to 5.1% at the end of 2006. The result has been an increase in benefit obligations (i.e., an experience loss), which is contributing to an increase in the cost of pension benefits as losses are amortized to earnings.

In accordance with the Corporation's accounting policy to amortize cumulative experience gains and losses in excess of 10 percent of the greater of the accrued benefit obligations or the market value of plan assets, the Corporation began amortizing a portion of the net cumulative experience losses on plan assets and accrued benefit obligations in 2003 for both pension benefit plans and other post employment benefit plans and continued this amortization during the three months and the year ended December 31, 2006.

The assumed annual health care cost trend rate increases used in measuring the accumulated post employment benefit obligations in the three months and the year ended December 31, 2006, are as follows: for drug costs, 8.5% starting in 2006 grading down over 7 years to 4.5%, and for other medical and dental costs, 4.0% for 2006 and thereafter. Combined with higher claims experience, the effect of these changes has been to increase the costs of other post employment benefits.

The effect of changes in these estimates and assumptions is mitigated by an AEUB decision to record the costs of employee future benefits when paid rather than accrued. Therefore, a significant portion of the benefit plans expense or income is unrecognized by the regulated operations, excluding Alberta Power (2000).

The sensitivities of key assumptions used in measuring accrued benefit obligations and benefit plan cost (income) for 2006 are outlined in the following table. The sensitivities of each key assumption have been calculated independently of changes in other key assumptions. Actual experience may result in changes in a number of assumptions simultaneously.

	2006 Pension Benefit Plans		2006 Other Post Employment Benefit Plans	
($ Millions)	Accrued Benefit Obligation	Benefit Plan Cost	Accrued Benefit Obligation	Benefit Plan Cost
Expected long term rate of return on plan assets				
1% increase [1]	-	(3.4)	-	-
1% decrease [1]	-	3.4	-	-
Liability discount rate				
1% increase [1]	(79.5)	(6.4)	(3.7)	(0.4)
1% decrease (1)	101.7	7.5	4.7	0.5
Future compensation rate				
1% increase [1]	22.9	2.9	-	-
1% decrease [1]	(20.8)	(2.6)	-	-
Long term inflation rate				
1% increase [1] [2] [3]	34.5	3.9	4.2	0.7
1% decrease [1] [3]	(60.4)	(6.9)	(3.4)	(0.5)

Notes:

(1) Sensitivities are net of the associated regulatory asset (liability) and unrecognized defined benefit plans cost, which reflect an AEUB decision to record costs of employee future benefits in the regulated operations, excluding Alberta Power (2000), when paid rather than accrued.

(2) The long term inflation rate for pension plans reflects the fact that pension plan benefit payments are indexed to increases in the Canadian Consumer Price Index to a maximum increase of 3.0% per annum.

(3) The long term inflation rate for other post employment benefit plans is the assumed annual health care cost trend rate described in the weighted average assumptions.

CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2007, the Corporation prospectively adopted the recommendations of the Canadian Institute of Chartered Accountants ("CICA") pertaining to financial instruments, hedging and comprehensive income. These recommendations require certain financial instruments and hedge positions to be recorded at their fair value. They also introduce the concept of comprehensive income and accumulated other comprehensive income. Financial instruments designated as "held-for-trading" and "available-for-sale" will be carried at their fair value while financial instruments classified as "loans and receivables" and "held-to-maturity" will be carried at their amortized cost. All derivatives will be carried on the consolidated balance sheet at their fair value, including derivatives designated as hedges. The effective portion of unrealized gains and losses on cash flow hedges and the cumulative foreign currency translation adjustments arising from self-sustaining investments in foreign operations will be carried in Accumulated Other Comprehensive Income, a component of Class A and Class B Share Owners Equity on the consolidated balance sheet. Any ineffective portions of gains and losses on hedges will be taken into earnings immediately. Changes in value of fair value hedges will be recognized in earnings as they occur. The Corporation is unable to determine at this time the impact of adopting these recommendations on earnings or assets of the Corporation.

Effective January 1, 2006, the Corporation retroactively adopted the CICA Emerging Issues Abstract regarding conditional asset retirement obligations. This abstract requires an entity to record a liability for an asset retirement obligation where the timing and/or method of settlement are conditional upon the occurrence of a future event that may or may not be within the control of the entity. Adoption of this abstract had no effect on the consolidated financial statements for the year ended December 31, 2006.

Effective January 1, 2006, the Corporation retroactively adopted the CICA Emerging Issues Abstract regarding stock based compensation for employees eligible to retire before the vesting date. This abstract requires an entity to recognize the compensation cost attributable to such an award over the period from grant date to the date the employee becomes eligible to retire. Since the Corporation does not have stock based compensation plans that contain such provisions, adoption of this abstract had no effect on the consolidated financial statements for the year ended December 31, 2006.

February 21, 2007

CANADIAN UTILITIES LIMITED

CONSOLIDATED FIVE-YEAR FINANCIAL SUMMARY

(Millions of Canadian dollars, except as indicated)		**2006**	2005	2004 [(1)]	2003	2002 [(2)]
EARNINGS						
Revenues		**2,430.4**	2,515.8	3,011.4	3,742.6	2,975.9
Operating expenses		**1,390.7**	1,553.9	2,107.5	2,868.7	2,169.8
Depreciation and amortization		**348.5**	311.5	291.5	269.2	243.9
Interest		**222.9**	210.0	203.7	190.3	184.1
Interest and other income		**(58.5)**	(36.6)	(94.1)	(33.4)	(136.2)
Income taxes		**167.1**	175.6	158.0	155.6	190.0
Dividends on equity preferred shares		**35.8**	35.8	35.8	33.1	18.2
Earnings attributable to Class A and Class B shares		**323.9**	265.6	309.0	259.1	306.1
SEGMENTED EARNINGS						
Utilities		**121.2**	106.0	168.7	121.3	177.8
Power generation [(3)]		**119.2**	105.2	82.0	94.1	77.3
Global enterprises [(3)]		**101.0**	78.8	70.1	54.8	44.4
Corporate and other/eliminations		**(17.5)**	(24.4)	(11.8)	(11.1)	6.6
Earnings attributable to Class A and Class B shares		**323.9**	265.6	309.0	259.1	306.1
BALANCE SHEET						
Property, plant and equipment		**5,426.1**	5,208.7	5,042.5	4,835.4	4,681.2
Total assets		**6,993.5**	6,817.8	6,617.5	6,237.6	6,075.8
Capitalization:						
Long term debt		**2,411.5**	2,231.0	2,171.0	1,805.3	1,916.9
Non-recourse long term debt		**626.7**	673.8	760.9	806.1	821.1
Equity preferred shares		**636.5**	636.5	636.5	636.5	486.5
Share owners' equity [(4)]		**2,324.7**	2,223.5	2,117.7	1,948.5	1,827.0
Total capitalization		**5,999.4**	5,764.8	5,686.1	5,196.4	5,051.5
CASH FLOWS						
Funds generated by operations		**657.5**	659.3	538.3	525.8	504.6
Purchase of property, plant and equipment		**567.7**	526.7	535.5	495.7	569.8
Financing (excluding Class A and B dividends)		**44.4**	(2.2)	333.8	(10.6)	384.3
Class A and B dividends		**176.7**	139.6	134.4	129.3	124.2
CLASS A & B SHARES						
Shares outstanding at end of year [(4)] (thousands)		**125,388**	126,892	126,783	126,767	126,824
Return on equity [(4)] (%)		**14.3**	12.2	15.2	13.7	17.7
Earnings per share [(4)] ($)		**2.57**	2.09	2.44	2.04	2.42
Dividends paid per share [(4)] [(5)] ($)		**1.40**	1.10	1.06	1.02	0.98
Equity per share [(4)] ($)		**18.54**	17.52	16.70	15.37	14.41
Stock market record - Class A non-voting shares ($)	High	**48.94**	46.20	32.00	29.80	30.05
	Low	**35.15**	29.55	25.71	22.55	24.40
	Close	**47.73**	43.98	30.16	28.93	25.605
Stock market record - Class B common shares ($)	High	**48.85**	45.82	31.95	29.375	30.25
	Low	**35.72**	29.63	25.70	22.75	24.50
	Close	**47.66**	43.85	31.95	29.00	26.325

(1) *Includes the gain on the transfer of retail energy supply businesses that occurred on May 4, 2004. Revenues and natural gas supply and purchased power costs after May 4, 2004 were reduced accordingly for 2004 and thereafter.*

(2) *Includes the gain on the sale of Viking-Kinsella property.*

(3) *In 2006, ASHCOR Technologies was transferred from the Global Enterprises Business Group to the Power Generation Business Group. Segmented figures for 2002 to 2005 have been reclassified to conform to the current basis of segmentation.*

(4) *Includes Class A non-voting shares and Class B common shares.*

(5) *Dividends paid per share include a Special Dividend of $0.25 paid to Class A and Class B share owners on September 1, 2006.*

CANADIAN UTILITIES LIMITED
CONSOLIDATED FIVE-YEAR OPERATING SUMMARY

(Millions of Canadian dollars, except as indicated)		**2006**	2005	2004	2003	2002
Utilities						
Natural gas distribution operations						
Purchase of property, plant and equipment		**167.4**	174.0	154.3	141.0	103.1
Pipelines (thousands of kilometres)		**35.9**	35.4	34.8	34.2	33.7
Maximum daily demand (terajoules)		**1,861**	1,919	2,049	1,831	1,670
Natural gas sold [1] (petajoules)		**-**	-	103	198	201
Natural gas distributed [1] (petajoules)		**219**	216	120	32	31
Total system throughput (petajoules)		**219**	216	223	230	232
Average annual use per residential customer (gigajoules)		**126**	131	134	134	136
Degree days	- Edmonton [2]	**3,819**	3,641	3,985	4,245	4,274
	- Calgary [3]	**3,910**	3,934	3,978	4,291	4,470
Customers at year-end (thousands)		**969.9**	939.6	914.3	887.8	862.0
Electric distribution and transmission operations						
Purchase of property, plant and equipment		**238.1**	212.2	223.4	171.6	162.4
Power lines (thousands of kilometres)		**70.1**	69.2	68.0	67.0	67.1
Electricity distributed (millions of kilowatt hours)		**10,286**	9,926	9,910	9,768	10,224
Average annual use per residential customer (kWh)		**7,495**	7,214	7,475	7,261	7,445
Customers at year-end (thousands)		**216.3**	210.9	206.2	202.3	197.8
Natural gas transportation operations						
Purchase of property, plant and equipment		**97.7**	84.3	47.9	33.6	47.3
Pipelines (thousands of kilometres)		**8.4**	8.3	8.3	8.3	8.3
Contract demand for pipelines system access (terajoules/day)		**5,032**	4,830	4,606	4,599	4,890
Power Generation						
Purchase of property, plant and equipment		**48.1**	41.2	77.0	131.7	236.0
Generating capacity (thousands of kilowatts)		**2,474**	2,474	2,474	2,397	2,036
Global Enterprises						
Purchase of property, plant and equipment		**14.2**	11.9	14.5	15.5	11.5
Natural gas processed (Mmcf/day)		**480**	476	427	399	420
Natural gas gathering lines (kilometres)		**1,000**	1,000	1,000	1,000	940

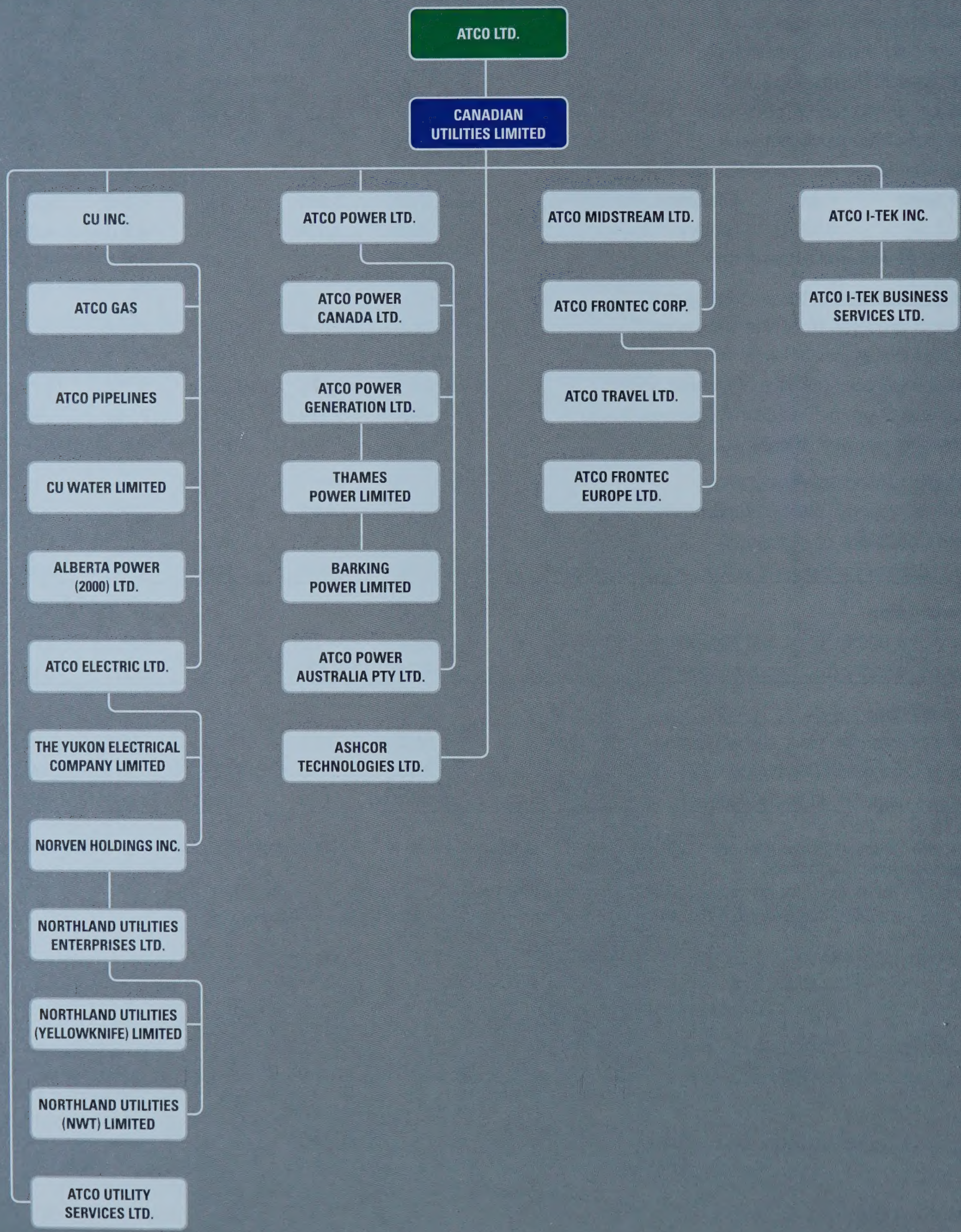
(1) *Effective May 2004, with the transfer of the retail energy supply businesses, ATCO Gas' existing sales service customers became transportation service customers.*

(2) *Degree days – Edmonton – are defined as the difference of the mean daily temperature from 14.5 degrees Celsius.*

(3) *Degree days – Calgary – are defined as the difference of the mean daily temperature from 15.5 degrees Celsius.*

Canadian Utilities Limited

ORGANIZATION CHART



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Corporate Director

Brian P. Drummond
Corporate Director

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Lead Director

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Ronald D. Southern
Chairman of the Board of Directors
Canadian Utilities Limited

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